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NORTHERN GREAT PLAINS RESOURCE PROGRAM, NATIONAL AND REGIONAL ENERGY CONSIDERATIONS WORK GROUP REPORT

Northern Great Plains Resource Program

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Analyzes the energy resources in the states of North Dakota, South Dakota, Montana and Wyoming and presents data on the potential for these resources to provide a share of the total national energy demand. Analyses in the following seven principle areas are presented: 1) Status of current development; 2) Energy use forecasts by region, state, sector and source; 3) Energy conservation; 4) Coal gasification and coal liquidfaction; 5) Transportation of energy from the region; 6) Electrical generation; 7) Status of technology; and 8) Future alternate energy sources. Data is also presented on three alternative hypothetical rates of coal development; minimum, intermediate and maximum rates. These are the basic models upon which six other Northern Great Plains Resources Program Work Groups analyzed potential impacts of coal development.

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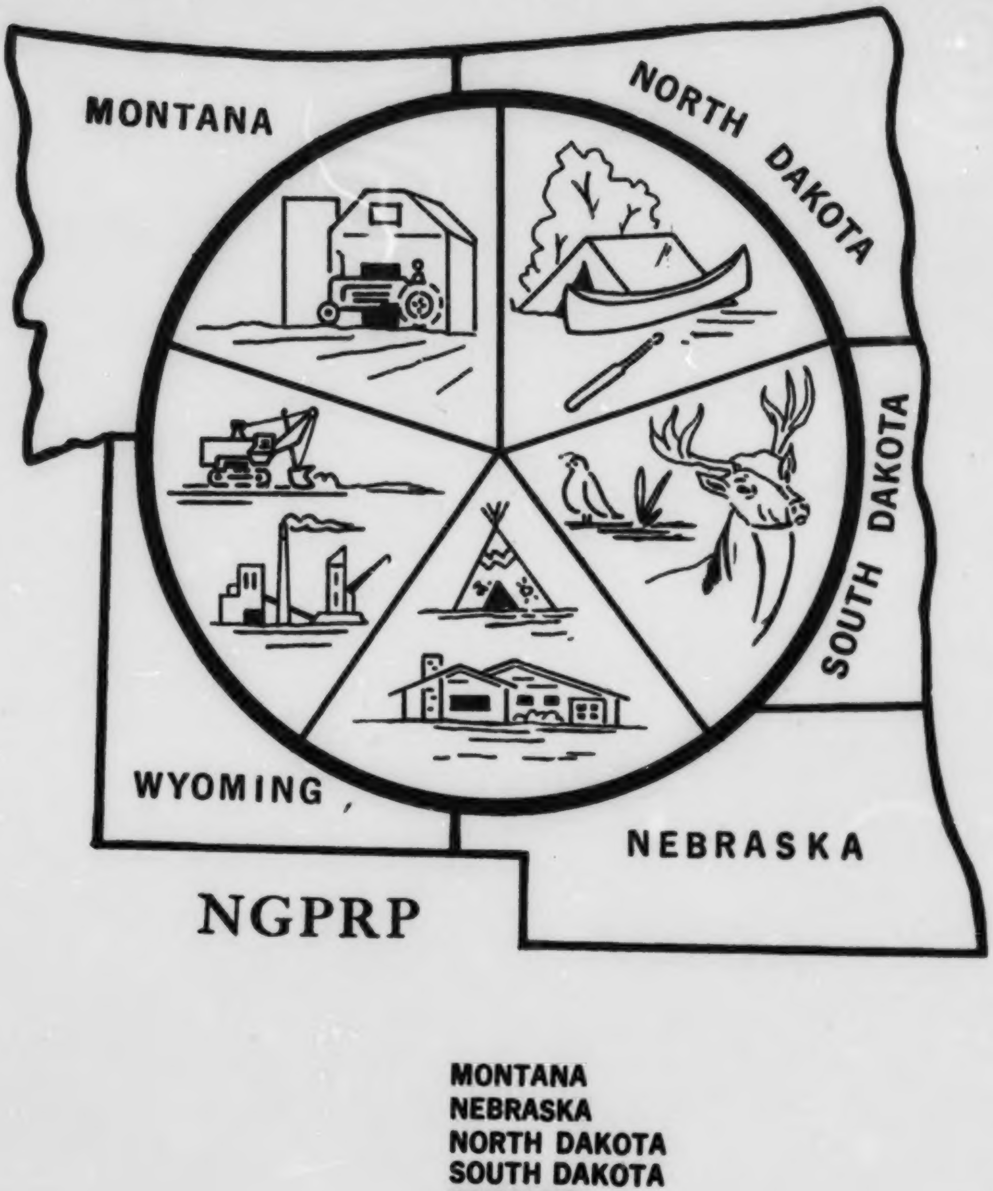
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NORTHERN GREAT PLAINS RESOURCES PROGRAM

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DISCUSSION DRAFT

FEBRUARY 1974

THIS REPORT WAS PREPARED PURSUANT TO A DIRECTIVE DATED OCTOBER 23, 1973, FROM THE PROGRAM MANAGER, NORTHERN GREAT PLAINS RESOURCES PROGRAM. PUBLICATION OF THE FINDINGS AND RECOMMENDATIONS HEREIN SHOULD NOT BE CONSTRUED AS REPRESENTING EITHER THE APPROVAL OR DISAPPROVAL OF THE SECRETARY OF THE INTERIOR, THE SECRETARY OF AGRICULTURE, THE ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY, OR THE STATES OF MONTANA, NEBRASKA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING. THE PURPOSE OF THIS REPORT IS TO PROVIDE INFORMATION AND ASSISTANCE TO THE PROGRAM MANAGEMENT TEAM IN THE PREPARATION OF THE DRAFT INTERIM REPORT ON THE NORTHERN GREAT PLAINS RESOURCES PROGRAM. THE PROGRAM MANAGEMENT TEAM IS RELEASING THIS DRAFT FOR PUBLIC USE WITHOUT CORRECTING INCONSISTENCIES OR REWRITING BECAUSE THE DELAY REQUIRED TO ACCOMPLISH THIS TASK WOULD DELAY THE TIMELY ISSUANCE OF THE REPORTS.

NORTHERN GREAT PLAINS RESOURCES PROGRAM

NATIONAL AND REGIONAL ENERGY CONSIDERATIONS WORKGROUP

DISCUSSION DRAFT--FEBRUARY/MARCH-1974

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PART I.

NORTHERN GREAT PLAINS REGION

SUMMARY OF ENERGY RESOURCES AND DEVELOPMENT

Part I. Northern Great Plains Region - Summary of Energy Resources and Development

The Northern Great Plains Region, as demarcated in this section, includes the entire States of North Dakota, South Dakota, Montana, Wyoming, and Nebraska. This coverage, which is broader than the one used in other sections, complements the approach used in Part II to forecast the energy requirements for the Region. Nebraska has been omitted from the following summaries because its energy resources are relatively insignificant. (Production and consumption data for fossil fuels in Nebraska are given in Appendix I, Tables 27-A through 29-A.)

The Region contains about 106 billion tons of measured and indicated coal reserves in beds of at least 60 inches thick for lignite and subbitiminous coal and at least 28 inches thick for bituminous coal. The coal accounts for about 27% of the Nation's total. However, the coal reserves considered to be economically recoverable probably totals less than 53 billion tons. The coal has a low sulfur content and is mostly of subbituminous rank. Most of it can be surface mined. Coal mining in the Region began in the late 1800's. In general, production declined sharply after the mid-1940's and reached a low in the late 1950's. The decline was due to the replacement of coal-fired locomotives with diesel-electric locomotives, and to the expanded use of hydropower and petroleum in other consuming sectors formerly dominated by coal. In recent years, however, production in the Region has increased to meet the demand from new coal-fired powerplants. The upward trend in coal production is expected to continue in the future. Table 2-A, Appendix I, lists the Region's production, consumption, and net outflow of coal for 1960-71.

Petroleum reserves in the Region at yearend 1972 consisted of 1,357 million barrels of crude oil, 5,595 billion cubic feet of natural gas, and 141 million barrels of natural gas liquids. Most of the reserves are in Wyoming and Montana. Commercial production began in 1894 in Wyoming and in 1916 in Montana. Wyoming is the Region's leading petroleum producer. In general, the outlook is favorable for sustained production because many areas have not yet been adequately tested. Table 3-A, Appendix I gives the production, consumption, and net outflow of petroleum; Table 4-A gives comparable data for natural gas.

Oil shale and tar sands are present in several States in the Region. The higher-grade oil shale deposits in parts of Wyoming are estimated to contain 4 billion barrels of oil that can be recovered with present-day technology.

The major reserves of uranium in the Region are in Wyoming, which has ranked second only to New Mexico in production in recent years.

NORTH DAKOTA

Coal.--North Dakota's measured and indicated reserves of lignite total about 36 billion tons, 9% of the Nations' total coal reserves. Lignite mining in North Dakota began about 1874. Production declined in the 1950's and early 1960's largely because the existing small lignite-fueled powerplants were not competitive with the hydroelectric powerplants built on the Missouri River. However, in the late 1960's production increased to supply new, larger lignite-fueled powerplants constructed near the mines. Production has risen steadily in recent years. It will continue to rise in the near future to meet the needs of several additional powerplants that are under construction or planned. Coal leasing activity has increased in recent years due to the possibility that coal gasification plants will be built in the State. Table 7-A, Appendix I, lists coal production-consumption data for 1960-71.

Crude oil.--Crude oil reserves in North Dakota at yearend 1972 were estimated at 166 million barrels, about 0.5 percent of the Nation's total. Production dates back to 1951, when the Beaver Lodge Field was discovered in Williams County. Peak production was 29.9 million barrels in 1966, after which the output declined, dropping to about 21 million barrels in 1972. The downtrend was due largely to the depletion of older fields and the lack of new discoveries. Table 8-A, Appendix I lists production-consumption data for crude petroleum for 1960-71.

The first of three North Dakota refineries was built in 1954. One was closed in 1957, leaving only two refineries in operation. In 1972 their combined throughput capacity was about 52,000 barrels per day.

Natural gas.--Natural gas reserves at yearend 1972 in the State totaled about 442 billion cubic feet, 0.2% of the Nation's total. Production began in the early 1900's, but no significant developments occurred until crude oil production increased during the mid 1950's. Gas production reached a high of 46 billion cubic feet in 1966. Table 9-A lists production-consumption data for 1960-71.

Reserves of natural gas liquids at yearend 1972 were estimated at 45 million barrels, about 0.7% of the Nation's total. The first natural gas processing plant began operations in 1954; two more were built in 1962. The peak production, 2.7 million barrels, was in 1966. The total processing capacity was 137 million cubic feet per day in 1972.

Uranium.--Uranium mining started in 1963 and ended in 1968. In 1965, the most recent year for which production data are available, 44,158 tons of uranium ash concentrate was produced from uraniferous lignite. Data for uranium reserves are not available.

SOUTH DAKOTA

Coal.--South Dakota's measured and indicated reserves of lignite total about 0.8 billion tons. Production began on a commercial scale with an output of 10,540 tons in 1913. After reaching a peak of about 70,000 tons in 1941, production declined to 20,000 tons in 1960 and 5,000 tons in 1967 and then ended in 1968. A 35-ton-per-day pilot plant for lignite gasification was built in Rapid City by Consolidation Coal Co. Operations began in 1972 to determine if lignite can be successfully converted into a gaseous fuel. A 430-MW lignite-fired powerplant, the Big Stone plant, under construction at Grant is expected to begin operating in 1975. Table 12-A gives production-consumption data for 1960-71.

Crude oil.--South Dakota's crude oil reserves were estimated to be comparatively insignificant in 1972. Production began in 1954 and reached a peak of 281,000 barrels in 1960. There are no petroleum refineries in the State. Table 13-A gives supply-demand data for 1960-71. Prospects for future discoveries in the State reportedly are not encouraging.

Natural gas.--Data for Natural gas reserves in the State are not available. Gas had been produced in Hughes County up through 1954 at the rate of about 5 million cubic feet per year. It was consumed locally for heating and cooking. Table 14-A lists natural gas consumption for 1960-71. A natural gas processing plant in Butte County, near the Wyoming border, processes gas produced in Wyoming.

Oil shale.--South Dakota has low-grade resources of oil shale and tar sands.

Uranium.--Uranium was discovered in the State in 1951. Production tonnages have been withheld since 1965, but they are apparently at relatively low levels. The outlook for a significant increase in production reportedly is not very optimistic. Data for reserves are not available.

MONTANA

Coal.--Montana's measured and indicated coal reserves are estimated to total 39 billion tons, about 10% of the Nation's total. Most of the reserves are in Big Horn, Powder River, and Rosebud Counties of the Fort Union Coal Region.

Coal production dates back to about 1880. The record high production during recent years represents a recovery from the late 1940's and the 1950's. During that period the output dropped from 4.8 million tons in 1944 to 305,000 tons in 1958. The decline occurred because coal-fired locomotives were replaced by diesel-powered locomotives, and oil and natural gas replaced coal as a fuelfor powerplants. In addition, hydroelectric power became more plentiful, and natural gas and petroleum acquired a large share of the market previously held by coal for residential and commercial heating.

The construction of new powerplants in Montana and the demand for low sulfur coal for powerplants in other States has revived Montana's coal industry. Coal production has risen from 519,000 tons in 1968 to more than a million tons in 1969 and about 8 million tons in 1972. Preliminary data indicates a total of almost 10 million tons in 1973. Surface mining accounts for virtually all production. The mines near Colstrip, Rosebud County, provide the bulk of the output. Table 17-A lists supply-demand data for 1960-71.

The future potential markets for the coal are principally powerplants in Montana and other States, the latter being supplied by unit trains. Several gasification plants have been proposed.

Crude oil.--Montana's crude oil reserves at yearend 1972 were estimated at 241 million barrels, about 0.7% of the Nation's total. Commercial production began in 1916 with an output of 44,900 barrels from the Elk Basin field. Production reached 11.9 million barrels in 1953 and continued to rise cyclically to a record high of 48.5 million barrels in 1968. Subsequent production declined, dropping to 33.9 million barrels in 1972. In general, the outlook for a sustained or moderately rising output is optimistic if active exploration and development programs are undertaken. In 1972 Montana's eight operating refineries had a throughput capacity of about 141,000 barrels per day. See Table 18-A for supply-demand data for 1960-71.

Natural gas.--Natural gas reserves at yearend 1972 totaled 1,064 billion cubic feet, about 0.4% of the country's total. Production began about 1915 to supply the town of Glendive, but it remained relatively small for most of the early years. Supply-demand for 1960-71 are given in Table 19-A. There is potential for an increase in production because the gas reserves are at relatively shallow depths and can be drilled at low cost.

Montana's reserves of natural gas liquids at yearend were estimated at 4.4 million barrels. In 1972 four natural gas processing plants were operating with a total capacity of 44 million cubic feet of gas per day. The peak production of natural gas liquids was estimated at 948,000 barrels in 1967. Production in recent years is estimated at about 500,000 barrels per year.

Oil shale.--Montana's oil shale deposits are low grade, with yields ranging from about one to 24 gallons per ton. Low-grade deposits of tar sands are also present.

Uranium.--Montana has uranium reserves, but there has been no production in recent years. Mining began in 1957 in Carbon County. Peak production was reached in 1959, when 9,912 pounds of uranium oxide was obtained from 2,890 tons of ore. The last reported production was 729 tons of ore in 1961. Data regarding reserves are withheld.

WYOMING

Coal.--Wyoming's measured and indicated reserves of coal total 29.9 billion tons and comprise almost 8% of the Nation's total.

Small-scale mining began in Wyoming in the late 1800's. Production reached 9.8 million tons in 1945 and then declined to a low of 1.6 million tons in 1958 because of a loss of markets as fuel for locomotives, powerplants, and residential and commercial heating. Beginning in the late 1950's and continuing through 1973, coal production rose gradually to satisfy the demand created by new coal-fired powerplants in Wyoming and other States. Production in 1972 reached an alltime high of 10.9 million tons. Preliminary data for 1973 indicate an output of 13.6 million tons. In 1972 about 45% of the coal produced in Wyoming was used in powerplants in the State, whereas the remainder was shipped to powerplants in other States. Table 22-A gives supply-demand data for 1960-71.

The outlook for increased production is favorable. Powerplants in Wyoming and other States are predicted to consume the bulk of the State's coal production in the next few decades. The railroads will continue to play an important part in the Wyoming coal industry, with unit trains transporting coal to markets outside the State. The use of coal for the production of synthetic fuels is expected to become significant after 1980. The U.S. Bureau of Mines began research on coal gasification near Hanna in 1972. Several private companies are interested in sites for possible future coal gasification projects.

Crude oil.--Wyoming's crude oil reserves at yearend 1972 were estimated at 950 million barrels, about 2.6% of the Nation's total. Oil production began in 1884, but it did not become significant until 1913, when the total output was about 2.3 million barrels. During the 1960's and 1970's the production ranged from about 134 to 160 million barrels annually. The total in 1972 was 140 million barrels. Preliminary data for 1973 indicate a rise to about 142 million barrels. The State's oil potential has not been fully realized because many areas have yet to be adequately tested, although some new prospects are at greater depths than earlier discoveries. Production and consumption data for 1960-71 are given in Table 23-A. In 1972 Wyoming's nine operating refineries had a throughput capacity of about 139,000 barrels per day.

Natural gas.--Natural gas reserves at yearend 1972 totaled 4,089 billion cubic feet, about 1.5% of the Nation's total. The development of the State's natural gas industry generally parallels the oil industry. In 1913 production was 2.3 billion cubic feet, mostly from the Salt Creek Field. Production in 1972 totaled 375 billion cubic feet. Preliminary data indicate a total of 384 billion cubic feet in 1973. The State's potential for natural gas production is expected to rise when new prospects are evaluated. Table 24-A gives supply-demand data for 1960-71.

Reserves of natural gas liquids at yearend 1972 were estimated at 92 million barrels, about 1.4% of the Nation's total. In 1972 the 27 natural gas processing plants in the State had a capacity of 1,194 million cubic feet of gas per day. The output of natural gas liquids reached 10.7 million barrels in 1972.

Oil shale and tar sands.--Wyoming's oil shale deposits contain about 4 billion barrels of oil that is estimated to be recoverable with present-day technology. The U.S. Bureau of Mines conducts oil shale research at its Laramie Energy Research Center. Two tracts totaling 10,203 acres southeast of Rock Springs were included among the six prototype areas for the oil shale leasing program of the Interior Department.

Wyoming has 24 documented tar sand deposits, half of which are in Fremont and Natrona Counties. They contain an estimated 30 billion barrels of oil, presumably oil in place and not necessarily all recoverable. No plans or programs are underway to develop the tar sands.

Uranium.--Recoverable reserves of uranium in Wyoming in 1972 totaled 195 million pounds of recoverable U_3O_8, which ranked second in the Nation. In general, the outlook is favorable for the increased growth of the industry in the State. The production ranks second in the Nation in recent years. The output during recent years was as follows, in million pounds recoverable U_3O_8: 1968, 5.9; 1969, 6.7; 1970, 6.3; 1971, 7.0; 1972, 8.5.

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APPENDIX I

PRODUCTION, CONSUMPTION, AND NET OUTFLOW OF ENERGY RESOURCES, 1960-1971

NORTHERN GREAT PLAINS REGION

Table 1A Total fossil Fuel Production, Consumption, and Net Outflow from the Northern Great Plains Region, 1960-1971

Year	Production Trillion Btu	Consumption Trillion Btu	Net Outflow Trillion Btu
1960	1,616.3	944.4	671.9
1961	1,736.5	971.6	764.9
1962	1,731.1	996.0	735.1
1963	1,758.7	1,020.7	738.0
1964	1,718.7	1,050.1	668.6
1965	1,726.5	1,085.9	640.6
1966	1,761.5	1,146.3	615.2
1967	1,761.7	1,189.6	572.1
1968	1,887.0	1,242.0	645.0
1969	1,999.4	1,303.7	695.7
1970	2,192.9	1,371.2	821.7
1971	2,248.7	1,448.2	800.5

Table 2-A Production, Consumption, and Net Outflow of Coal from the Northern Great Plains Region, 1960-1971

Year	Production		Consumption		Net Outflow	
	Thousand short tons	Trillion Btu	Thousand short tons	Trillion Btu	Thousand short tons	Trillion Btu
1960	4,882.0	125.2	4,448.3	112.1	433.7	13.1
1961	5,644.0	144.4	4,584.1	121.9	1,059.9	22.5
1962	5,702.0	145.9	4,781.2	123.9	920.8	22.0
1963	5,882.0	150.1	5,048.1	128.3	833.9	21.8
1964	6,097.0	155.4	5,396.4	135.4	700.6	20.0
1965	6,366.0	161.9	5,836.5	145.0	529.5	16.9
1966	7,642.0	193.4	6,978.9	171.9	663.1	21.5
1967	8,120.0	204.3	7,481.8	182.5	638.2	21.8
1968	8,835.0	221.4	8,105.3	195.6	729.7	25.8
1969	9,796.0	243.8	8,864.0	211.2	932.0	32.6
1970	16,308.0	405.8	9,774.0	230.0	6,534.0	175.8
1971	21,191.0	527.2	10,873.0	252.7	10,318.0	274.5

Table 3-A Production, Consumption, and Net Outflow of Petroleum from the Northern Great Plains Region, 1960-1971

	Production		Consumption		Net Outflow	
Year	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu
1960	218,100.0	1,233.6	96,463.0	533.7	121,637.0	699.9
1961	229,544.0	1,319.6	98,389.0	540.3	131,155.0	779.3
1962	226,630.0	1,301.7	100,484.0	547.5	126,146.0	754.2
1963	231,743.0	1,314.8	102,806.0	556.1	128,937.0	758.7
1964	224,014.0	1,251.7	105,442.0	565.9	118,572.0	685.8
1965	224,150.0	1,244.5	108,617.0	578.7	115,533.0	665.8
1966	221,270.0	1,227.0	110,910.0	591.7	110,360.0	635.3
1967	220,963.0	1,232.8	113,669.0	607.0	107,294.0	625.8
1968	241,559.0	1,338.8	116,894.0	624.3	124,665.0	714.5
1969	244,340.0	1,358.4	120,629.0	644.0	123,711.0	714.4
1970	242,405.0	1,351.9	124,922.0	666.9	117,483.0	685.0
1971	225,824.0	1,257.4	129,819.0	693.5	96,005.0	563.9

Table 4-A Production, Consumption, and Net Outflow of Natural Gas from the Northern Great Plains Region, 1960-1971

	Production		Consumption		Net Outflow 1/	
Year	Million cubic feet	Trillion Btu	Million cubic feet	Trillion Btu	Million cubic feet	Trillion Btu
1960	249,769.0	257.5	288,464.0	298.6	-38,695.0	-41.1
1961	264,418.0	272.5	299,029.0	309.4	-34,611.0	-36.9
1962	274,986.0	283.5	313,761.0	324.6	-38,775.0	-41.1
1963	284,935.0	293.8	324,970.0	336.3	-40,035.0	-42.5
1964	302,270.0	311.6	336,918.0	348.8	-34,648.0	-37.2
1965	310,326.0	320.1	349,959.0	362.2	-39,633.0	-42.1
1966	330,847.0	341.1	369,726.0	382.7	-38,879.0	-41.6
1967	314,855.0	324.6	387,143.0	400.1	-72,288.0	-75.5
1968	316,946.0	326.8	408,839.0	422.1	-91,893.0	-95.3
1969	385,322.0	397.2	434,973.0	448.5	-49,651.0	-51.3
1970	422,105.0	435.2	460,790.0	474.3	-38,685.0	-39.1
1971	450,185.0	464.1	486,914.0	502.0	-36,729.0	-37.9

1/ Negative figures indicate consumption greater than production.

Table 5-A Generation, Sales, and Outflow of Electricity from North Dakota, South Dakota, Nebraska, Montana, and Wyoming - 1960-1971

	Net Generation		Sales		Net Outflow 1/	
Year	Million kWhr	Trillion Btu	Million kWhr	Trillion Btu	Million kWhr	Trillion Btu
1960	15,412	52.5	14,970	51.0	442	1.5
1961	17,113	58.3	15,582	53.2	1,531	5.1
1962	18,407	62.9	17,586	60.0	821	2.9
1963	20,821	71.0	18,083	61.7	2,738	9.3
1964	22,559	76.9	19,200	65.6	3,359	11.3
1965	25,440	86.8	20,740	70.8	4,700	16.0
1966	27,466	93.8	22,548	76.9	4,918	16.9
1967	29,778	101.6	23,334	79.6	6,444	22.0
1968	32,534	111.0	25,532	87.1	7,002	23.9
1969	36,714	125.2	28,033	95.7	8,681	29.5
1970	38,452	131.1	29,219	99.6	9,233	31.5
1971	41,536	141.6	30,167	102.9	11,369	38.7

1/ Difference of sales and net generation of electricity. Kilowatt-hours converted to British thermal units (Btu) using a rate of 3,412 Btu/kWhr.

Table 6-A Total Fossil Fuel Production, Consumption, and Net Outflow from North Dakota, 1960-1971

Year	Production trillion Btu	Consumption trillion Btu	Net Outflow trillion Btu
1960	218.8	149.8	69.0
1961	236.6	157.4	79.2
1962	251.0	156.5	94.5
1963	249.1	156.8	92.3
1964	259.3	158.1	101.2
1965	265.3	160.6	104.7
1966	301.9	184.7	117.2
1967	301.1	191.3	109.8
1968	307.0	198.9	108.1
1969	290.3	207.5	82.8
1970	310.7	217.0	93.7
1971	317.4	228.8	88.6

Table 7-A Production, Consumption and Outflow of Coal from North Dakota, 1960-71

	Production		Consumption		Net Outflow	
Year	Thousand short tons	Trillion Btu	Thousand short tons	Trillion Btu	Thousand short tons	Trillion Btu
1960	2,525.0	64.8	1,977.7	50.1	547.3	14.7
1961	2,726.0	69.7	1,880.3	54.2	845.7	15.5
1962	2,733.0	69.9	1,792.8	49.3	940.2	20.6
1963	2,399.0	61.2	1,713.9	45.3	685.1	15.9
1964	2,637.0	67.2	1,642.6	42.1	994.4	25.1
1965	2,732.0	69.4	1,576.8	39.4	1,155.2	30.0
1966	3,543.0	89.6	2,467.7	60.8	1,075.3	28.8
1967	4,156.0	104.6	2,644.7	64.5	1,511.3	40.1
1968	4,487.0	112.4	2,859.6	69.0	1,627.4	43.4
1969	4,704.0	117.1	3,115.5	74.2	1,588.5	42.9
1970	5,639.0	140.3	3,415.5	80.4	2,223.5	59.9
1971	6,075.0	151.1	3,764.0	87.7	2,311.0	63.4

Table 8-A Production, Consumption, and Outflow of Petroleum from North Dakota, 1960-1971

	Production		Consumption		Net Outflow	
Year	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu
1960	23,872.0	133.9	15,613.0	83.9	8,259.0	50.0
1961	25,654.0	146.2	15,992.0	85.9	9,662.0	60.3
1962	27,223.0	155.2	16,392.0	88.1	10,831.0	67.1
1963	27,415.0	154.1	16,817.0	90.4	10,598.0	63.7
1964	28,248.0	156.5	17,268.0	92.8	10,980.0	63.7
1965	28,879.0	159.1	17,740.0	95.6	11,139.0	63.5
1966	29,866.0	164.3	17,973.0	96.9	11,893.0	67.4
1967	27,980.0	154.8	18,237.0	98.4	9,743.0	56.4
1968	27,754.0	152.3	18,514.0	100.0	9,240.0	52.3
1969	25,162.0	138.6	18,804.0	101.6	6,358.0	37.0
1970	24,342.0	134.4	19,108.0	103.2	5,234.0	31.2
1971	23,778.0	131.4	19,418.0	105.9	4,360.0	25.5

Table 9-A Production, Consumption, and Outflow of Natural Gas from North Dakota, 1960-1971

	Production		Consumption		Net Outflow 1/	
Year	Million cubic feet	Trillion Btu	Million cubic feet	Trillion Btu	Million cubic feet	Trillion Btu
1960	19,483.0	20.1	15,317.0	15.8	4,166.0	4.3
1961	20,100.0	20.7	16,844.0	17.3	3,256.0	3.4
1962	25,155.0	25.9	18,534.0	19.1	6,621.0	6.8
1963	32,798.0	33.8	20,401.0	21.1	12,397.0	12.7
1964	34,512.0	35.6	22,464.0	23.2	12,048.0	12.4
1965	35,652.0	36.8	24,722.0	25.6	10,930.0	11.2
1966	46,585.0	48.0	26,049.0	27.0	20,536.0	21.0
1967	40,462.0	41.7	27,494.0	28.4	12,968.0	13.3
1968	41,023.0	42.3	29,020.0	29.9	12,003.0	12.4
1969	33,587.0	34.6	30,644.0	31.7	2,943.0	2.9
1970	34,889.0	36.0	32,350.0	33.4	2,539.0	2.6
1971	33,864.0	34.9	34,194.0	35.2	-330.0	-0.3

1/ Negative figures indicate consumption greater than production.

Table 10-A Generation, sales and Outflow of Electricity in North Dakota, 1960-1971

Year	Net Generation Million kWhr	 Trillion Btu	Sales Million kWhr	 Trillion Btu	Net Outflow [1] Million kWhr	 Trillion Btu
1960	1,780	6.1	1,382	4.7	398	1.4
1961	2,223	7.6	1,482	5.1	741	2.5
1962	2,114	7.2	1,662	5.7	452	1.5
1963	2,190	7.5	1,799	6.1	391	1.4
1964	2,729	9.3	1,950	6.7	779	2.6
1965	3,249	11.1	2,127	7.3	1,122	3.8
1966	3,624	12.4	2,252	7.7	1,372	4.7
1967	5,355	18.3	2,486	8.5	2,869	9.8
1968	5,660	19.3	2,647	9.0	3,013	10.3
1969	6,130	20.9	2,773	9.5	3,357	11.4
1970	6,664	22.7	2,968	10.1	3,696	12.6
1971	8,268	28.2	3,188	10.9	5,080	17.3

[1] Difference of sales and net generation of electricity. Kilowatt-hours converted to British thermal units (Btu) using a rate of 3,412 Btu/kWhr.

Table 11-A Total Fossil Fuel Production, Consumption and Net Outflow from South Dakota, 1960-1971

Year	Production Trillion Btu	Consumption Trillion Btu	Net Outflow 1/ Trillion Btu
1960	2.1	116.7	-114.6
1961	1.8	119.4	-117.6
1962	1.5	122.6	-121.1
1963	1.6	126.9	-125.3
1964	1.7	132.3	-130.6
1965	1.5	139.8	-138.3
1966	1.6	142.0	-140.4
1967	1.3	145.1	-143.8
1968	1.0	149.1	-148.1
1969	0.9	154.1	-153.2
1970	0.9	160.8	-159.9
1971	1.3	169.3	-168.0

1/ Negative figures indicate consumption greater than production.

Table 12-A Production, Consumption, and Outflow of Coal from South Dakota, 1960-1971

	Production		Consumption		Net Outflow 1/	
Year	Thousand short tons	Trillion Btu	Thousand short tons	Trillion Btu	Thousand short tons	Trillion Btu
1960	20.0	0.5	494.4	12.5	-474.4	-12.0
1961	18.0	0.5	507.1	12.9	-489.1	-12.4
1962	18.0	0.5	524.3	13.3	-506.3	-12.8
1963	16.0	0.4	546.7	13.9	-530.7	-13.5
1964	13.0	0.3	575.2	14.7	-562.2	-14.4
1965	10.0	0.3	613.2	15.7	-603.2	-15.4
1966	10.0	0.3	656.6	16.6	-646.6	-16.3
1967	5.0	0.1	723.3	18.0	-718.3	-17.9
1968	W	W	820.1	20.1	-820.1	-20.1
1969	0	0	954.9	23.1	-954.9	-23.1
1970	0	0	1,137.4	27.2	-1,137.4	-27.2
1971	0	0	1,398.0	32.4	-1,398.0	-32.4

1/ Negative figures indicate consumption greater than production.

Table 13-A Production, Consumption, and Outflow of Petroleum from South Dakota, 1960-1971

	Production		Consumption		Net Outflow 1/	
Year	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu
1960	281.0	1.6	14,845.0	78.4	-14,564.0	-76.8
1961	233.0	1.3	15,298.0	80.6	-15,065.0	-79.3
1962	169.0	1.0	15,832.0	83.2	-15,663.0	-82.2
1963	215.0	1.2	16,501.0	86.5	-16,286.0	-85.3
1964	247.0	1.4	17,401.0	90.6	-17,154.0	-89.2
1965	219.0	1.2	18,732.0	96.5	-18,513.0	-95.3
1966	239.0	1.3	18,653.0	97.0	-18,414.0	-95.7
1967	211.0	1.2	18,674.0	97.8	-18,463.0	-96.6
1968	187.0	1.0	18,779.0	98.8	-18,592.0	-97.8
1969	158.0	0.9	18,960.0	100.1	-18,802.0	-99.2
1970	160.0	0.9	19,209.0	101.8	-19,049.0	-100.9
1971	233.0	1.3	19,562.0	104.1	-19,329.0	-102.8

1/ Negative figures indicate consumption greater than production.

Table 14-A Production, Consumption, and Outflow of Natural Gas from South Dakota, 1960-1971

	Production		Consumption		Net Outflow[1]	
Year	Million cubic feet	Trillion Btu	Million cubic feet	Trillion Btu	Million cubic feet	Trillion Btu
1960	0	0	24,882.0	25.8	-24,882.0	-25.8
1961	0	0	25,009.0	25.9	-25,009.0	-25.9
1962	0	0	25,260.0	26.1	-25,260.0	-26.1
1963	0	0	25,623.0	26.5	-25,623.0	-26.5
1964	0	0	26,090.0	27.0	-26,090.0	-27.0
1965	0	0	26,697.0	27.6	-26,697.0	-27.6
1966	0	0	27,476.0	28.4	-27,476.0	-28.4
1967	0	0	28,286.0	29.3	-28,286.0	-29.3
1968	0	0	29,128.0	30.2	-29,128.0	-30.2
1969	0	0	30,004.0	30.9	-30,004.0	-30.9
1970	0	0	30,915.0	31.8	-30,915.0	-31.8
1971	0	0	31,832.0	32.8	-31,832.0	-32.8

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[1] Negative figures indicate consumption greater than production.

Table 15-A Generation, Sales, and Outflow of Electricity in South Dakota, 1960-1971

	Net Generation		Sales		Net Outflow 1/	
Year	Million kWhr	Trillion Btu	Million kWhr	Trillion Btu	Million kWhr	Trillion Btu
1960	1,700	5.8	1,651	5.6	49	0.2
1961	1,714	5.8	1,776	6.1	-62	-.3
1962	2,175	7.4	1,923	6.6	252	.8
1963	3,467	11.8	2,014	6.9	1,453	4.9
1964	3,601	12.3	2,126	7.3	1,475	5.0
1965	4,335	14.8	2,239	7.6	2,096	7.2
1966	5,291	18.1	2,330	7.9	2,961	10.2
1967	5,480	18.7	2,555	8.7	2,925	10.0
1968	6,137	20.9	2,689	9.2	3,448	11.7
1969	6,880	23.5	2,839	9.7	4,041	13.8
1970	7,306	24.9	3,023	10.3	4,283	14.6
1971	8,391	28.6	3,228	11.0	5,163	17.6

1/ Difference of sales and net generation of electricity. Negative figures indicate sales (demand) for electricity greater than net generation. Kilowatt-hours converted to British thermal units (Btu) using a rate of 3,412 Btu/kWhr.

Table 16-A Total Fossil Fuel Production, Consumption, and Net Outflow from Montana, 1960-1971

Year	Production Trillion Btu	Consumption Trillion Btu	Net Outflow Trillion Btu
1960	217.1	187.3	29.8
1961	225.9	190.1	35.8
1962	225.9	197.0	28.9
1963	218.6	200.5	18.1
1964	209.4	204.4	5.0
1965	223.8	208.9	14.9
1966	242.4	216.1	26.3
1967	237.2	219.8	17.4
1968	307.5	227.1	80.4
1969	316.7	236.0	80.7
1970	345.5	245.8	99.7
1971	406.4	254.6	151.8

Table 17-A Production, Consumption, and Outflow of Coal from Montana, 1960-1971

	Production		Consumption		Net Outflow 1/	
Year	Thousand short tons	Trillion Btu	Thousand short tons	Trillion Btu	Thousand short tons	Trillion Btu
1960	310.0	8.0	419.7	10.7	-106.7	-2.7
1961	371.0	9.5	429.2	10.9	- 58.2	-1.4
1962	382.0	9.8	443.9	11.3	- 61.9	-1.5
1963	343.0	8.8	466.5	11.8	-123.5	-3.0
1964	346.0	8.8	499.4	12.6	-153.4	-3.8
1965	364.0	9.3	546.5	13.9	-182.5	-4.6
1966	419.0	10.6	584.0	14.6	-165.0	-4.0
1967	371.0	9.3	631.7	15.6	-260.7	-6.3
1968	519.0	13.0	690.4	16.8	-171.4	-3.8
1969	1,030.0	25.6	761.9	18.3	268.1	7.3
1970	3,447.0	85.8	848.3	20.0	2,598.7	65.8
1971	7,064.0	175.8	952.0	22.2	6,112.0	153.6

1/ Negative figures indicate consumption greater than production.

Table 18-A Production, Consumption, and Outflow of Petroleum from Montana, 1960-1971

	Production		Consumption		Net Outflow	
Year	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu
1960	30,758.0	174.6	21,100.0	120.9	9,658.0	53.7
1961	31,455.0	181.5	21,391.0	120.7	10,064.0	60.8
1962	32,088.0	185.2	21,724.0	120.8	10,364.0	64.4
1963	31,372.0	178.8	22,097.0	121.2	9,275.0	57.6
1964	31,132.0	174.8	22,505.0	121.9	8,627.0	52.9
1965	33,255.0	185.5	22,973.0	123.0	10,282.0	62.5
1966	35,909.0	200.2	23,087.0	124.4	12,822.0	75.8
1967	35,977.0	201.2	23,260.0	126.2	12,647.0	75.0
1968	49,333.0	274.6	23,494.0	128.3	25,839.0	146.3
1969	44,482.0	248.6	23,798.0	130.8	20,684.0	117.8
1970	38,479.0	215.7	24,181.0	133.8	14,298.0	81.9
1971	35,149.0	196.9	24,648.0	137.5	10,501.0	59.4

Table 19-A Production, Consumption, and Outflow of Natural Gas from Montana, 1960-1971

	Production		Consumption		Net Outflow 1/	
Year	Million cubic feet	Trillion Btu	Million cubic feet	Trillion Btu	Million cubic feet	Trillion Btu
1960	33,418.0	34.5	53,815.0	55.7	-20,397.0	-21.2
1961	33,901.0	34.9	56,393.0	58.5	-22,492.0	-23.6
1962	29,955.0	30.9	62,452.0	64.9	-32,497.0	-34.0
1963	30,026.0	31.0	64,892.0	67.5	-34,866.0	-36.5
1964	25,051.0	25.8	67,045.0	69.9	-41,994.0	-44.1
1965	28,105.0	29.0	69,533.0	72.0	-41,428.0	-43.0
1966	30,685.0	31.6	74,087.0	77.1	-43,402.0	-45.5
1967	25,866.0	26.7	75,163.0	78.0	-49,297.0	-51.3
1968	19,313.0	19.9	79,043.0	82.0	-59,730.0	-62.1
1969	41,229.0	42.5	83,896.0	86.9	-42,667.0	-44.4
1970	42,705.0	44.0	89,095.0	92.0	-46,390.0	-48.0
1971	32,720.0	33.7	92,016.0	94.9	-59,296.0	-61.2

1/ Negative figures indicate consumption greater than production.

Table20-4 Generation, Sales, and Outflow of Electricity in Montana, 1960-1971

Year	Net Generation		Sales		Net Outflow 1/	
	Million kWhr	Trillion Btu	Million kWhr	Trillion Btu	Million kWhr	Trillion Btu
1960	5,992	20.4	5,111	17.4	881	3.0
1961	6,780	23.1	5,246	17.9	1,534	5.2
1962	7,051	24.1	5,552	18.9	1,499	5.2
1963	6,595	22.5	5,729	19.5	866	3.0
1964	7,360	25.1	6,241	21.3	1,119	3.8
1965	8,882	30.3	6,893	23.5	1,989	6.8
1966	8,611	29.4	7,794	26.6	817	2.8
1967	9,119	31.1	7,532	25.7	1,587	5.4
1968	9,495	32.4	8,559	29.2	936	3.2
1969	10,444	35.6	10,098	34.5	346	1.1
1970	10,026	34.2	10,007	34.1	19	.1
1971	10,653	36.3	10,141	34.6	512	1.7

1/ Difference of sales and net generation of electricity. Kilowatt-hours converted to British thermal units (Btu) using a rate of 3,412 Btu/kWhr.

Table 21-A Total Fossil Fuel Production, Consumption, and Net Outflow from Wyoming, 1960-1971

Year	Production Trillion Btu	Consumption Trillion Btu	Net Outflow Trillion Btu
1960	1,022.9	206.1	816.8
1961	1,110.7	212.0	898.7
1962	1,088.8	218.9	869.9
1963	1,147.0	226.2	920.8
1964	1,125.5	235.3	890.2
1965	1,125.8	245.5	880.3
1966	1,124.4	257.2	867.2
1967	1,135.0	270.3	864.7
1968	1,186.7	285.5	901.2
1969	1,314.0	304.5	1,009.5
1970	1,463.0	323.9	1,139.1
1971	1,461.2	346.9	1,114.3

Table 22-A Production, Consumption, and Net Outflow of Coal from Wyoming, 1960-1971

	Production		Consumption		Net Outflow	
Year	Thousand short tons	Trillion Btu	Thousand short tons	Trillion Btu	Thousand short tons	Trillion Btu
1960	2,024.0	51.9	987.0	24.2	1,037.0	27.7
1961	2,529.0	64.7	1,155.2	28.2	1,373.8	36.5
1962	2,569.0	65.7	1,354.7	33.1	1,214.3	32.6
1963	3,124.0	79.7	1,591.8	38.8	1,532.2	40.9
1964	3,101.0	79.1	1,874.9	45.7	1,226.1	33.4
1965	3,260.0	82.9	2,207.4	53.5	1,052.6	29.4
1966	3,670.0	92.9	2,392.4	57.4	1,277.6	35.5
1967	3,588.0	90.3	2,597.8	61.6	990.2	28.7
1968	3,829.0	96.0	2,825.7	66.3	1,003.3	29.7
1969	4,062.0	101.1	3,079.0	71.4	983.0	29.7
1970	7,222.0	179.7	3,359.7	77.1	3,862.3	102.6
1971	8,052.0	200.3	3,671.0	83.6	4,381.0	116.7

Table 23-A Production, Consumption, and Net Outflow of Petroleum from Wyoming, 1960-1971

	Production		Consumption		Net Outflow	
Year	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu
1960	138,503.0	783.8	20,678.0	123.6	117,825.0	660.2
1961	146,917.0	845.3	21,141.0	124.4	125,776.0	720.9
1962	141,281.0	811.7	21,616.0	125.2	119,665.0	686.5
1963	150,037.0	851.8	22,106.0	126.0	127,931.0	725.8
1964	144,461.0	807.6	22,608.0	126.9	121,853.0	680.7
1965	143,991.0	799.7	23,104.0	128.0	120,887.0	671.7
1966	140,719.0	780.6	23,504.0	129.0	117,215.0	651.6
1967	142,812.0	797.2	24,031.0	130.5	118,781.0	666.7
1968	150,498.0	834.5	24,695.0	132.6	125,803.0	701.9
1969	161,896.0	900.0	25,509.0	135.1	136,387.0	764.9
1970	167,498.0	934.3	26,483.0	138.6	141,015.0	795.7
1971	156,102.0	869.0	27,628.0	142.1	128,474.0	726.9

Table 24-A Production, Consumption, and Net Outflow of Natural Gas from Wyoming, 1960-1971

Year	Production		Consumption		Net Outflow	
	Million cubic feet	Trillion Btu	Million cubic feet	Trillion Btu	Million cubic feet	Trillion Btu
1960	181,610.0	187.2	56,334.0	58.3	125,276.0	128.9
1961	194,674.0	200.7	57,396.0	59.4	137,278.0	141.3
1962	204,996.0	211.4	58,607.0	60.6	146,389.0	150.8
1963	209,060.0	215.5	59,363.0	61.4	149,697.0	154.1
1964	231,631.0	238.8	60,568.0	62.7	171,045.0	176.1
1965	235,849.0	243.2	61,825.0	64.0	174,025.0	179.2
1966	243,381.0	250.9	68,532.0	70.8	174,849.0	180.1
1967	240,074.0	247.5	75,876.0	78.2	164,198.0	169.3
1968	248,481.0	256.2	84,217.0	86.6	164,264.0	169.6
1969	303,517.0	312.9	95,507.0	98.0	208,010.0	214.9
1970	338,520.0	349.0	105,608.0	108.2	232,912.0	240.8
1971	380,105.0	391.9	117,542.0	121.2	262,563.0	270.7

Table 25-A Generation, Sales, and Outflow of Electricity in Wyoming, 1960-1971

	Net Generation		Sales		Net Outflow 1/	
Year	Million kWhr	Trillion Btu	Million kWhr	Trillion Btu	Million kWhr	Trillion Btu
1960	1,588	5.4	1,422	4.9	166	0.5
1961	1,966	6.7	1,642	5.6	324	1.1
1962	2,288	7.8	1,967	6.7	321	1.1
1963	3,146	10.7	2,396	8.2	750	2.5
1964	3,353	11.4	2,588	8.8	765	2.6
1965	3,570	12.2	2,806	9.6	764	2.6
1966	4,315	14.7	2,965	10.1	1,350	4.6
1967	4,007	13.7	2,945	10.0	1,062	3.7
1968	4,456	15.2	3,131	10.7	1,325	4.5
1969	5,893	20.1	3,372	11.5	2,521	8.6
1970	6,485	22.1	3,539	12.1	2,946	10.0
1971	6,458	22.0	3,666	12.5	2,792	9.5

1/ Difference of sales and net generation of electricity. Kilowatt-hours converted to British thermal units (Btu) using a rate of 3,412 Btu/kWhr.

Table 26-A Total Fossil Fuel Production, Consumption, and Net Outflow from Nebraska, 1960-1971

Year	Production Trillion Btu	Consumption Trillion Btu	Net Outflow 1/ Trillion Btu
1960	155.4	284.5	-129.1
1961	161.5	292.7	-131.2
1962	163.9	301.0	-137.1
1963	142.4	310.3	-167.9
1964	122.8	320.0	-197.2
1965	110.1	331.1	-221.0
1966	91.2	346.3	-255.1
1967	87.1	363.1	-276.0
1968	84.8	381.4	-296.6
1969	77.5	401.6	-324.1
1970	72.8	423.7	-350.9
1971	62.4	448.6	-386.2

1/ Negative figures indicate consumption greater than production.

Table 27-A Production, Consumption, and Outflow of Coal from Nebraska, 1960-1971

	Production		Consumption		Net Outflow 1/	
Year	Thousand short tons	Trillion Btu	Thousand short tons	Trillion Btu	Thousand short tons	Trillion Btu
1960	0	0	569.5	14.6	-569.5	-14.6
1961	0	0	612.3	15.7	-612.3	-15.7
1962	0	0	665.5	16.9	-665.5	-16.9
1963	0	0	729.2	18.5	-729.2	-18.5
1964	0	0	804.3	20.3	-804.3	-20.3
1965	0	0	892.6	22.5	-892.6	-22.5
1966	0	0	878.2	22.5	-878.2	-22.5
1967	0	0	884.3	22.8	-884.3	-22.8
1968	0	0	909.5	23.4	-909.5	-23.4
1969	0	0	952.7	24.2	-952.7	-24.2
1970	0	0	1,013.1	25.3	-1,013.1	-25.3
1971	0	0	1,088.0	26.8	-1,088.0	-26.8

1/ Negative figures indicate consumption greater than production.

Table 28-A Production, Consumption, and Outflow of Petroleum From Nebraska, 1960-1971

	Production		Consumption		Net Outflow 1/	
Year	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu	Thousand barrels	Trillion Btu
1960	24,686.0	139.7	24,227.0	126.9	459.0	12.8
1961	25,285.0	145.3	24,567.0	128.7	718.0	16.6
1962	25,869.0	148.6	24,920.0	130.2	949.0	18.4
1963	22,704.0	128.9	25,285.0	132.0	-2,581.0	-3.1
1964	19,926.0	111.4	25,660.0	133.7	-5,734.0	-22.3
1965	17,806.0	99.0	26,068.0	135.6	-8,262.0	-36.6
1966	14,537.0	80.6	27,693.0	144.4	-13,156.0	-63.8
1967	14,053.0	78.4	29,467.0	154.1	-15,414.0	-75.7
1968	13,787.0	76.4	31,412.0	164.6	-17,625.0	-88.2
1969	12,642.0	70.3	33,558.0	176.4	-20,916.0	-106.1
1970	11,926.0	66.6	35,941.0	189.5	-24,015.0	-122.9
1971	10,562.0	58.8	38,563.0	203.9	-28,001.0	-145.1

1/ Negative figures indicate consumption greater than production.

Table 29-A Production, Consumption, and Outflow of Natural Gas from Nebraska, 1960-1971

	Production		Consumption		Net Outflow 1/	
Year	Million cubic feet	Trillion Btu	Million cubic feet	Trillion Btu	Million cubic feet	Trillion Btu
1960	15,258.0	15.7	138,116.0	143.0	-122,858.0	-127.3
1961	15,743.0	16.2	143,387.0	148.3	-127,644.0	-132.1
1962	14,880.0	15.3	148,908.0	153.9	-134,028.0	-138.6
1963	13,051.0	13.5	154,691.0	159.8	-141,640.0	-146.3
1964	11,094.0	11.4	160,751.0	166.0	-149,657.0	-154.6
1965	10,720.0	11.1	167,183.0	173.0	-156,463.0	-161.9
1966	10,196.0	10.6	173,582.0	179.4	-163,386.0	-168.8
1967	8,453.0	8.7	180,324.0	186.2	-171,871.0	-177.5
1968	8,129.0	8.4	187,431.0	193.4	-179,302.0	-185.0
1969	6,989.0	7.2	194,922.0	201.0	-187,933.0	-193.8
1970	5,991.0	6.2	202,882.0	208.9	-196,831.0	-202.7
1971	3,496.0	3.6	211,330.0	217.9	-207,834.0	-214.3

1/ Negative figures indicate consumption greater than production.

Table 30-A: Generation Sales, and Outflow of Electricity in Nebraska, 1960-1971

	Net Generation		Sales		Net Outflow 1/	
Year	Million kWhr	Trillion Btu	Million kWhr	Trillion Btu	Million kWhr	Trillion Btu
1960	4,352	14.8	5,404	18.4	-1,052	-3.6
1961	4,430	15.1	5,436	18.5	-1,006	-3.4
1962	4,779	16.4	6,482	22.1	-1,703	-5.7
1963	5,423	18.5	6,145	21.0	-722	-2.5
1964	5,516	18.8	6,295	21.5	-779	-2.7
1965	5,404	18.4	6,675	22.8	-1,271	-4.4
1966	5,625	19.2	7,207	24.6	-1,582	-5.4
1967	5,817	19.8	7,816	26.7	-1,999	-6.9
1968	6,786	23.2	8,506	29.0	-1,720	-5.8
1969	7,367	25.1	8,951	30.5	-1,584	-5.4
1970	7,971	27.2	9,682	33.0	-1,711	-5.8
1971	7,766	26.5	9,944	33.9	-2,178	-7.4

1/ Difference of sales and net generation of electricity. Negative figures indicate sales (demand) for electricity greater than net generation. Kilowatt-hours converted to British thermal units (Btu) using a rate of 3,412 Btu/kWhr.

Table 31-A. Consumption of Energy Resources in the Household and Commercial Sector, Northern Great Plains Region, 1960, 1965, 1971

Year	Coal (million tons)	Petroleum (million barrels)	Natural Gas (billion cu. ft)	Electricity Distributed (million kilowatt hours)
Region:				
1960	1.0	16.7	125.5	8876
1965	.6	18.3	156.4	12,498
1971	.3	27.3	206.7	18,050
North Dakota:				
1960	.5	4.2	6.7	1197
1965	.3	4.6	11.6	1835
1971	.1	5.5	17.6	2716
South Dakota:				
1960	.1	4.3	14.9	1240
1965	.1	4.5	18.9	1855
1971	insig.	5.9	21.3	2792
Montana:				
1960	.2	2.5	28.8	1678
1965	.2	2.6	34.0	2360
1971	.1	3.9	41.1	3281
Wyoming:				
1960	.1	1.2	13.7	1264
1965	insig.	1.4	18.8	1406
1971	insig.	3.4	32.4	1463
Nebraska:				
1960	.1	4.5	61.4	3497
1965	insig.	5.2	73.1	5042
1971	insig.	8.6	94.3	7798

Table 32-A. Consumption of Energy Resources in the Industrial Sector Northern Great Plains Region, 1960, 1965, 1971

Year	Coal (million tons)	Petroleum (million Barrels)	Natural Gas (billion cu. ft.)	Electricity Distributed (million kwhr)
Region:				
1960	.8	3.8	117.8	5995
1965	1.3	6.0	145.7	8148
1971	.7	8.3	201.7	11,456
North Dakota:				
1960	.4	.7	8.5	185
1965	.3	1.0	13.2	292
1971	.2	1.1	16.2	472
South Dakota:				
1960	.1	.1	5.5	411
1965	.3	2.1	5.6	384
1971	.2	.6	7.3	436
Montana:				
1960	insig.	1.5	24.2	3334
1965	.1	.8	33.3	4439
1971	insig.	2.2	49.1	6772
Wyoming:				
1960	.1	1.3	40.2	158
1965	.2	1.7	40.8	1400
1971	.2	2.4	74.2	1638
Nebraska:				
1960	.2	.2	39.4	1907
1965	.4	.4	52.8	1633
1971	.1	2.0	54.9	2138

Table 33-A. Consumption of Energy Resources to the Transportation Sector Northern Great Plains Region, 1960, 1965, 1971

Year	Petroleum (million Barrels)	Natural Gas (billion cu. ft.)	Electricity Distributed (million kilowatt hours)
Region:			
1960	56.7	8.5	99
1965	64.4	11.3	94
1971	74.3	22.0	98
North Dakota:			
1960	9.6	insig.	0
1965	11.5	insig.	0
1971	11.5	insig.	0
South Dakota:			
1960	9.9	insig.	0
1965	11.6	insig.	0
1971	12.0	insig.	0
Montana:			
1960	11.4	.5	99
1965	13.6	.4	94
1971	14.0	.8	98
Wyoming:			
1960	7.4	1.8	0
1965	7.9	2.2	0
1971	10.9	8.0	0
Nebraska:			
1960	18.4	6.2	0
1965	19.8	8.7	0
1971	25.9	13.2	0

PART II.

NORTHERN GREAT PLAINS REGION
ENERGY FORECAST THROUGH THE YEAR 2000
BY REGION, STATE, SECTOR, AND SOURCE

HISTORICAL PERSPECTIVE 1/

In the time period from 1960 to 1971 gross energy consumption 2/ in the Northern Great Plains Region (NGPR) increased from 1,047.6 trillion Btu to 1,652.7 trillion Btu while net energy inputs 3/increased from 893.5 trillion Btu to 1,254.6 trillion Btu over the same timeframe. These represent a 4.2 percent and a 3.1 percent annual rate of growth, respectively. During the 1960 to 1971 period the Nation's gross energy inputs grew at an annual rate of 4.0 percent while the national net energy inputs grew at a rate of 3.7 percent per year.

For the same period gross energy inputs grew by 4.5 percent per year in North Dakota; 6.2 percent in South Dakota; 3.2 percent in Montana; 4.9 percent in Wyoming, and 3.5 percent in Nebraska. Net energy inputs rose at an annual rate of 1.9 percent in North Dakota, 2.7 percent in South Dakota, 2.8 percent in Montana, 3.5 percent in Wyoming, and 3.9 percent in Nebraska.

Another indicator of the NGPR increasing energy intensiveness is the energy usage per capita during the 1960-71 period. Gross energy usage per capita has risen from 280.9 million Btu in 1960 to 428.7 million Btu in 1971, while net energy usage has increased from 239.6 million Btu per capita in 1960 to 325.4 million Btu per capita in 1971.

1/ The following discussion is based on table 1 of the text.

2/ Gross energy inputs refer to the total inputs to the electrical, industrial, household and commercial, and transportation sectors, but does not include energy exported; i.e., out-of-State/region coal shipments.

3/ Net energy inputs refer to the inputs in the final consuming sectors (industrial, transportation, and household and commercial).

In contrast, the national average gross energy per capita has risen from 246.8 million Btu in 1960 to 333.3 million Btu in 1971, while the national net energy usage per capita has risen from 211.5 million Btu in 1960 to 274.8 million Btu in 1971. The following table illustrates the historical trends in energy usage per capita for selected years:

	Gross energy per capita (trillion Btu)		Net energy per capita (million Btu)	
Year	Region	U.S.	Region	U.S.
1960	280.9	246.8	239.6	211.5
1965	327.7	274.4	265.5	232.1
1971	428.7	333.3	325.4	274.8
Avg. Annual growth rate (%)	3.9	2.8	2.8	2.4

Gross energy consumption per capita and net energy consumption per capita have also increased in each of the five States from 1960 to 1971, as shown in table 1. North Dakota, South Dakota, and Nebraska gross/net energy per capita ratios have been consistently below the regional averages, while Montana and Wyoming have been consistently above.

One further indicator of the trend in energy consumption is the energy consumed per dollar of personal income (constant 1958 dollars). This ratio has been quite erratic in growth since 1960, but in general, it has had a downward trend falling from 151.3 thousand Btu per dollar in 1960 to 147.9 thousand Btu per dollar in 1965 to finally 143.5 thousand Btu per dollar in 1971. This ratio is a rough indicator of the efficiency of utilization of energy in the NGPR economy and illustrates a long-term increase in efficiency.

As shown in table 1, the energy per personal income ratio has remained relatively constant for Montana in the period from 1960 to 1971, erratically rising in North Dakota, and steadily rising in both South Dakota and Wyoming, while steadily falling in Nebraska.

Appendix 1 illustrates historical production, consumption, and net outflows of energy by energy source (i.e., coal, petroleum, etc.) and by State for the years 1960-71. In addition, part I of this study discusses the historical development, production and resources of the energy industry of the NGPR in detail.

Table 1. Northern Great Plains States - Selected Economic and Energy Indicators 1960, 1965 and 1971.

	Gross Energy Inputs (trillion Btu)	Net Energy Inputs (trillion Btu)	Population (thousands)	Personal Income (million $ 1958)	Energy/$ Income (thousand Btu)	Gross Energy/ Capita (million Btu)	Net Energy/ Capita (million Btu)
1960							
North Dakota	161.2	129.9	632	1,056	52.7	255.1	205.3
South Dakota	128.9	111.6	681	1,184	108.9	189.3	163.9
Montana	249.7	199.8	675	1,344	185.8	369.9	296.0
Wyoming	212.7	190.5	330	729	291.8	644.5	577.3
Nebraska	295.1	261.7	1,411	2,609	113.1	209.1	185.5
Region	1,047.6	893.5	3,729	6,922	151.3	280.9	239.6
1965							
North Dakota	186.7	144.9	649	1,383	135.0	287.7	223.3
South Dakota	179.9	139.2	692	1,404	128.1	260.0	201.2
Montana	296.6	223.5	706	1,583	187.4	420.1	316.6
Wyoming	254.7	208.6	331	785	324.5	769.5	630.2
Nebraska	342.9	305.4	1,470	3,368	101.8	233.3	207.8
Region	1,260.8	1,021.6	3,848	8,523	147.9	327.7	265.5
1971							
North Dakota	262.0	159.6	625	1,656	158.2	419.2	255.4
South Dakota	248.6	149.4	670	1,730	143.7	371.0	223.0
Montana	352.9	270.7	708	1,919	183.9	498.4	382.3
Wyoming	360.3	277.4	340	992	363.2	1,059.7	815.9
Nebraska	428.9	397.5	1,512	5,221	82.1	283.7	262.9
	1,652.7	1,254.6	3,855	11,518	143.5	428.7	325.4

SOURCES: Survey of Current Business, August 1972, U.S. Dept. of Commerce;
OBERS Projections - 1972, volume 5; U.S. Water Resources Council
Economic Report of the President, January 1973.

THE TOTAL ENERGY FORECAST - INTERMEDIATE SCENARIO [1]

Total regional gross energy inputs to the Northern Great Plains Region are forecast to increase from 1,683.8 trillion Btu in 1971 to 6,374 trillion Btu in 2000, indicating an average annual growth rate of 4.7 percent for the period, and compared to a national growth rate for consumption of 3.6 percent for the same period.

Petroleum consumption will increase in the region from 129.5 million barrels in 1971 to 224 million barrels in 2000 although its share of the region's total gross inputs will decline from 41.2 percent to 19.3 percent.

Natural gas usage will increase from 487.1 billion cubic feet to 765 billion cubic feet but its share of the regional market will decline from 29.8 percent in 1971 to 12.4 percent in 2000.

Hydropower consumption during this period is expected to remain constant at 23.2 billion kilowatt hours. Its share of regional total gross inputs is expected to fall from 14.1 percent to 3.1 percent in the year 2000. By 2000 nuclear inputs for electric generation will total 40 billion kilowatt hours, equal to 5.6 percent of the region's total gross inputs in that year.

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[1] The following discussion is based on Table 2 of the text and tables 1 through 12, and 44, of appendix II - B.

Coal consumption in the Northern Great Plains Region is expected to increase from the 1971 total of 11 million short tons to 252 million short tons in 2000. Its share of regional total gross inputs will rise from 14.9 percent to 59.6 percent over the period. In addition, 110 million tons of coal will be exported to other regions by the year 2000.

Total regional gross inputs representing 2.4 percent of total U.S. energy consumption in 1971 are expected to rise to 3.3 percent of total U.S. consumption in the year 2000. Gross energy consumption per capita is expected to increase from 437 million Btu per capita to 1,407 million Btu per capita from 1971 through 2000. Net energy consumption per capita is expected to increase from 328 million Btu to 517 million Btu over the same period. The lower rate of net energy growth is explained by the movement toward more secondary forms of energy consumption (principally electrical energy and synthetic gas in relation to the Northern Great Plains Region).

Net exports of energy from the Northern Great Plains Region to other regions are expected to increase from 841.2 trillion Btu in 1971 to 2,340 trillion Btu in the year 2000.

Table 2 Selected NGP Region Economic & Energy Indicators, 1971 actual, and projected to the year 2000 - Inter-mediate scenario

	Gross Energy Inputs (trillion Btu)	Net Energy Inputs (trillion Btu)	Population[1] (thousands)	Personal Income[1] (Million $ 1958)	Gross Energy/ Personal Income (thousand Btu)	Gross Energy/ Capita (million Btu)	Net Energy/ Capita (million Btu)
North Dakota							
1971	262.0	159.6	625	1,656	158	419	255
1975	266	175	625	2,084	128	426	280
1980	402	196	632	2,146	187	636	310
1985	738	217	640	2,874	257	1,153	339
2000	1,834	281	681	4,195	436	2,693	413
South Dakota							
1971	248.6	149.4	670	1,730	144	371	223
1975	256	161	670	2,219	115	382	240
1980	283	177	672	2,272	123	417	263
1985	316	191	682	3,042	104	463	280
2000	589	239	732	4,446	132	805	327
Montana							
1971	352.9	270.7	708	1,919	184	498	382
1975	387	303	708	2,486	156	547	428
1980	517	346	720	2,583	200	718	431
1985	912	389	735	3,476	262	1,241	529
2000	1,577	523	790	5,085	310	1,996	662
Wyoming							
1971	360.3	227.3	340	992	363	1,060	669
1975	411	297	346	1,256	327	1,188	858
1980	504	343	359	1,335	378	1,404	955
1985	795	387	375	1,814	438	2,120	1,032
2000	1,132	532	426	2,763	410	2,657	1,249
Nebraska							
1971	460.0	408.8	1,512	5,221	88	304	270
1975	5[illegible]2	418	1,547	5,572	10[illegible]	363	289
1980	658	511	1,608	6,202	106	409	318
1985	795	573	1,673	7,519	106	475	342
2000	1,242	766	1,900	13,107	95	654	403
Region							
1971	1,683.8	1,265.9	3,855	11,518	146	437	328
1975	1,8[illegible]	1,384	3,896	13,617	138	482	355
1980	2,3[illegible]1	1,573	3,991	14,538	16[illegible]	592	394
1985	3,556	1,757	4,105	18,725	190	866	428
2000	6,374	2,341	4,529	29,596	215	1,407	517

NOTE: [1] From OBERS Projections, 1972, vol. 5, Water Resources Council.

THE HOUSEHOLD AND COMMERCIAL, INDUSTRIAL, AND TRANSPORTATION SECTOR FORECASTS 1/
(Intermediate Scenario)

Household and Commercial Sector

Total energy inputs to the Household and Commercial Sector of the NGPR are expected to increase from 430.5 trillion Btu in 1971 to 861 trillion Btu in the year 2000, for an average annual growth rate of 2.4 percent. In contrast, the total national Household and Commercial Sector inputs will increase from 17,441 trillion Btu to 39,530 trillion Btu, an average growth rate of 2.9 percent over the same period.

Significant changes in energy inputs to this sector, paralleling the expected national trends, are expected to occur during this period in the NGPR. From the 1971 2.1 percent of inputs, coal is expected to lose all of its share of this market. Petroleum's share is expected to decline from 33.7 percent in 1971 to 26.6 percent in 2000 (paralleling a national decline of the 1971 37.5 percent to 28.1 percent in 2000). Natural gas, however, will decline from 49.5 percent of the total sectoral energy inputs in the region in 1971 to 40.2 percent in 2000 (total natural gas sectoral inputs on the national level will decline from 42.2 percent in 1971 to 27.2 percent in 2000.). Paralleling national trends, a significant increase will occur in the region's electrical consumption, rising from 14.8 percent in 1971 to 33.2 percent in 2000.

1/ The following discussions are based on Appendix II-A, tables 13 through 18 for the Household and Commercial Sector, tables 19 through 24 for the Industrial Sector, and tables 25 through 30 for the Transportation Sector.

Trends for the individual States are shown in tables 14 through 18. In 1971 North Dakota's household sector inputs were 14.1 percent of the total regional sectoral inputs and in 2000 North Dakota will retain 13.9 percent. South Dakota's share of regional sectoral inputs is expected to decline from the 1971 figure of 14.7 percent to 13.2 percent in 2000. Montana will decline from 18.5 percent to 16.8 percent over the same time period. Wyoming will increase from 13.8 percent of the total regional sectoral inputs in 1971 to 16.5 percent in 2000, while Nebraska will increase from 38.9 percent to 39.5 percent over the same period.

Industrial Sector

Total sector energy inputs to the NGPR Industrial Sector are expected to increase from 316.3 trillion Btu in 1971 to 687 trillion Btu in the year 2000 for an average annual growth rate of 2.7 percent. These regional sectoral inputs, representing 1.4 percent of the total national sectoral inputs in 1971, will decline to 1.2 percent in 2000. The national industrial sector energy inputs are expected to increase from 22,263 trillion Btu in 1971 to 57,780 trillion Btu in 2000, with a corresponding growth rate of 3.3 percent.

Significant changes in energy inputs are expected to occur in the energy inputs of the regional industrial sector. Coal's share of this market is expected to decline from 6.8 percent in 1971 to 4.8 percent in 2000, compared to the projected national decline of 19.7 percent to 11.6 percent. Petroleum's share is expected to increase from 15.1 to 17.8 percent, while on the national level petroleum is expected to increase from 23.8 percent in 1971 to 25.5 percent of the total sector inputs in the year 2000. Natural gas will decrease on the regional level from 65.7 percent in 1971 to 50.8 percent of the total regional sector inputs in 2000, paralleling a national decline in natural gas inputs to the sector of 46.1 percent to 31.0 percent over the same time period. A significant change is expected to occur in electricity's market share, increasing from 12.4 percent of the total energy inputs to the region's industrial sector in 1971 to 26.6 percent in 2000. This increase corresponds to a national increase of 10.4 percent to 27.0 percent.

Montana's share of the total region's industrial sector inputs is expected to increase from 27.8 percent in 1971 to 34.1 percent in 2000. The other four States will experience a decline in their share of the region's sectoral inputs (North Dakota - 9.8 percent to 9.2 percent; South Dakota - 5.5 percent to 3.6 percent; Wyoming - 31.8 percent to 31.0 percent; and Nebraska - 25.2 percent to 22.1 percent in the year 2000.).

Transportation Sector

Total sector inputs to the NGPR Transportation Sector are expected to increase from 422.3 trillion Btu in 1971 to 695 trillion Btu in the year 2000, representing 1.6 percent of the Nation's total sector inputs.

No significant shifts in energy inputs are expected. Petroleum's share of this market will show a slight decline from 94.5 percent in 1971 to 93.8 percent in the year 2000 compared with a national decline of 95 percent to 93.8 percent. Natural gas will increase its share of total inputs from 5.4 percent in 1971 to 6.2 percent in the year 2000, compared with a national natural gas increase in the transportation sector from 4.9 percent in 1971 to 6.1 percent in the year 2000.

These same trends will hold true for both Montana and Wyoming although Wyoming consumed much more natural gas for pipeline transportation than Montana. North Dakota and South Dakota are expected to consume only petroleum products as they have in the past. Petroleum's share of the total gross sector inputs in Nebraska will rise slightly while the natural gas share of sectoral inputs in Nebraska will decline.

Changes are also expected in each States' share of the total regional sector inputs. North Dakota's total inputs will increase from 61.2 trillion Btu in 1971 to 91 trillion Btu in the year 2000, an average annual growth rate of 1.4 percent. South Dakota's share of the total regional transportation sector energy inputs will decline from 15.2 percent in 1971 to 13.7 percent in 2000.

Montana's inputs to the transportation sector will increase from 77.7 trillion Btu in 1971 to 118 trillion Btu in 2000, an increase of 1.4 percent per year. Montana's share of total regional sector inputs will likewise fall from 18.4 percent to 17.0 percent over the same time period.

In Wyoming, energy inputs to the transportation sector will increase from 67.3 trillion Btu in 1971 to 127 trillion Btu in 2000, at an annual growth rate of 2.2 percent and a subsequent increase in the share of total regional sectoral inputs from 15.9 percent to 18.3 percent.

Nebraska's total gross energy inputs to the transportation sector is expected to increase from 152.0 trillion Btu in 1971 to 264 trillion Btu in the year 2000, at an annual growth rate of 1.6 percent. Nebraska's share of total sector inputs will subsequently rise from 36.0 percent in 1971 to 37.9 percent in the year 2000.

Methodology Used:

In projecting future energy consumption in the Household and Commercial Sector, the Industrial Sector, and the Transportation Sector of the Northern Great Plains States, a naive statistical model was used, tempered with certain judgments on future energy consumption.

Cross-sectional multiple regression analysis was used to determine relationships between energy consumption (tables 31-A through 34-A, Appendix I) and population and personal income (table 1, Historical Perspective) Sectoral consumption by sector and State was then forecast using the population and personal income data in table 2 , of the Total Energy Forecast Section (p.II-6). The major problem with this methodology was in the lack of any consistent historical data base for sectoral consumption by fuel source, other than for the years 1960, 1965, and 1971. Therefore, Least Squares Trend analysis was used to determine trends of future individual fuels consumption by State (tables 1-A through 30-A, Appendix I), trends of future gross energy consumption, and future sectoral consumption by fuel source.

In the Industrial Sector, forecasts of future earnings by industry 1/ were examined to obtain trends of future industrial production by State. No allowance was made for any future uranium enrichment facilities in the region, with the recent cancellation of the Reynolds Project.

In the Transportation Sector, Federal Highway Administration forecasts 2/ on both motor vehicles and highway use of motor fuel by State 2/ were also examined in relationship to energy consumption in that sector. New electric railroads were not factored into the transportation forecast due to additional analysis needed in the area (particularly by Union Pacific) before any decisions can be made upon construction.

1/ OBERS Projections, U.S. Water Resources Council, vol. 5, 1972.
2/ A Guide for Forecasting Traffic on the Interstate System, FHWA, April 1971.

The results of all of the above analyses were then reconciled by judgments to produce consistent sets of energy consumption figures by State, sector and fuel source. The judgments used were principally in adjusting NGPR sectoral consumption of energy more closely to projected future national trends. (See Part III of this study)

It is in these three sectors that the National Energy Considerations Workgroup feel least confident about the NGPR energy forecast, due to the lack of a consistent historical data base and the subjective judgments that had to be employed. Nevertheless, the forecasts for the Household and Commercial, Industrial, and the Transportation Sectors, appear at this time to be well within reason.

THE ELECTRICAL SECTOR FORECAST-(INTERMEDIATE SCENARIO) 1/

The demand for energy inputs to the NGPR electrical generation forecast will grow rapidly in the future. Installed generating capacity in the region will rise from 8,347 megawatts in 1971 to 57,748 megawatts in the year 2000 for an average annual growth rate of 6.9 percent as compared to the projected national growth rate of 5.8 percent. Net generation in the region will increase from 41.5 billion kilowatt hours in 1971 to 316.7 billion kilowatt hours in 2000 for average growth rate of 7.3 percent as compared to the national average projected growth rate of 6.1 percent.

The energy resource inputs necessary to achieve these high growth rates will increase from the 1971 regional total of 520.8 trillion Btu to 2,685 trillion Btu in the year 2000, for an annual growth rate of 5.8 percent. The largest increase for fuel inputs to the electrical sector of the NGPR will be for coal which is expected to rise from the 1971 input figure of 10 million tons to 130 million tons in the year 2000. Coal's share of the region's total inputs will subsequently rise from 42.3 percent of total inputs to 72.6 percent in 2000. Petroleum products consumption in the electrical sector will rise from 0.7 million barrels in 1971 to 21 million barrels in 2000 and its share of the market will rise from 0.9 percent of the total inputs to 4.7 percent in 2000.

Natural gas inputs will decline from 56.7 billion cubic feet to 51 billion cubic feet and its share of the market will decline from 11.2 to 1.9 percent in the 1971-2000 time period. Nuclear power inputs will increase (in the State of Nebraska) from 0 in 1971 to 40 billion

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1/ The following discussion is based on tables 31-43 of Appendix II-A.

kilowatt hours in 2000 to capture 13.4 percent of the total sector inputs. Hydropower inputs will remain relatively constant in the region through 2000 at about 23 billion kilowatt hours, although the share of inputs will decline from 45.6 percent in 1971 to only 7.3 percent in the year 2000. Total electrical sector inputs in the region were 3.0 percent of the total national sector inputs in 1971 and are expected to be only 3.3 percent of the national figure in the year 2000.

The NGPR exported 11.4 billion bilowatt hours to other States in 1971 and this figure for net exports is expected to increase to 179 billion kilowatt hours by the year 2000. The most significant increase in net exports of electrical energy will occur in the State of North Dakota which is expected to export 70.6 billion kilowatt hours by the year 2000.

The electrical sector forecast was developed utilizing forecasts by the Federal Power Commission Bureau of Power 2/. See Appendix II-B - Additional Data, Section A.

2/ FPC, Bureau of Power, Staff Report on Coal Burning Steam Electric Generating Plants in Montana, Wyoming, North Dakota, and South Dakota for 1973-2000. Submitted Sept. 1973 to National Energy Considerations Work Group, NGPRP, and subsequent report for the State of Nebraska submitted October 1973.

The following excerpts from the aforementioned Bureau of Power report on Montana, Wyoming, North Dakota, and South Dakota will serve as methodology behind the electrical sector projections for the four States. 3/

"This report considers the potential for growth of coal-fired electric generating capacity in the four-state area of Montana, Wyoming, North Dakota, and South Dakota, through the year 2000, using the coal resources of the area. In a general sense, all such generating plants now projected could be categorized as mine-mouth plants, even though in some cases relatively short, dedicated transportation facilities may be necessary. The actual siting of such plants, in view of the present state of the art of steam condensing techniques for large units, is dependent upon the technical and economic balance that must be reached among a number of various factors, including fuel and water resources. Because of this, specific locations for plants projected in the far term have not been attempted, however, there are projections of capacity and generation by individual states in the area. If current trends are followed, it would be expected that certain acceptable sites would be exploited to maximum potential in order to minimize environmental impact as well as maximize economics.

Close coordination of planning and operating procedures exists among the electric utilities of the four-state area and beyond, and includes all segments of ownership. Some utilities serve across state lines, and some, such as the Bureau of Reclamation are regional in nature. This point is emphasized because some subsequent relations made between in-state electric energy consumption and generating capacity will need to be evaluated in the broader area of regional and national needs.

The Federal Power Commission, in order to better fulfill its responsibilities concerning adequacy and reliability of power supply sponsored the organization of the electric utility industry into nine Regional Electric Reliability Councils covering the contiguous United States. In accordance with FPC Order 383, the nine councils submit an annual report to the Commission which up to this time has included industry load and capacity projections for the ensuing ten-year period. Future reporting, however, will include certain projections for a twenty-year period. Generally, utilities in the states of Montana and Wyoming are members of and report to the Western Systems Coordinating Council (WSCC) and those in North Dakota and South Dakota participate in the Mid-Continent Area Reliability Coordination Agreement (MARCA). WSCC and MARCA are two of the nine regional councils."

3/ FPC - Bureau of Power Staff Report, ibid. page 16.

"High voltage transmission interconnections are in constant use across state and regional lines among the various utilities and are a part of the vast system of interconnections which connect together essentially all of the electric utilities in the contiguous United States, except for a part of Texas. However, because of geography, population densities, location of load and industrial centers, and historical relationships, the utilities in Montana and Wyoming are oriented westward in areas of mutual planning, joint ownership of facilities, firm power interchanges, and the like; whereas the North and South Dakota utilities emphasize such relations with utilities to their east. The logical continuation of this practice is recognized in longer range projections presented in this report and has the effect of continuing to site a certain amount of coal-fired generating capacity in the four states, the output of which is dedicated to serve loads outside the area over the interconnected electric transmission system. In the detailing of these projections, statistical data filed with the Federal Power Commission for the 1960-1972 period were considered, together with industry projections filed with the Commission for the 1973-1982 period under Order 383. The projected growth of steam-electric generating capacity in the four-state area from approximately 2,900 megawatts in 1973 to 36,900 megawatts through the year 2000, predominantly coal-fired, is just one of the several possible alternatives that could generally track current and projected trends.

This capacity projection has been combined with reasonably expected load and capacity factors to yield a projected coal consumption. In general, except for the Libby project in Montana, large hydroelectric installations to produce significant amounts of energy were not projected. The relatively insignificant use of natural gas as a boiler fuel was assumed to remain at present levels, although this could be too optimistic in light of current FPC views concerning the use of natural gas as boiler fuel. The gas burned in 1972 produced only 1.2 percent of the total electric energy produced in this area and this projected level of gas consumption would produce less than 0.2 percent of the projected electric energy requirements for the year 2000. Its substitution by oil or coal would not materially alter the quantities of those fuels consumed. An increase in the amount of distillate oil consumption for combustion peaking turbines and for fire stabilization in large coal-fired plants was included. Because of the large coal resources in the area, no nuclear capacity was projected. In addition to coal consumption by plants located within the study area, the known projected use of area coals in steam-electric plants outside the area is tabulated. However, this potential use of the area's coal resources by distant electric utilities is subject to detailed economic studies involving both electric and transportation industries, and is influenced by some highly variable conditions. This potential coal use was not included nor evaluated in this study."

"The above staff projection is more modest than that of the regional reliability council if the council projection be extended to the year 2000 at the same rate as the 1973-1982 period. The councils' projected annual rate of total capacity additions for the 1973-1982 preiod is 8.4 percent. This rate is apparently considered to be within the abilities of the various utilities involved and is considered by the Bureau of Power staff to be generally attainable. However, if this rate is extended out to the year 2000, a total installed capacity of 64,175 megawatts results, compared to the staff projection of 42,650 megawatts. The additional 21,525 megawatts of installed capacity would no doubt be coal-fired. If the same level of confidence is given to this rate of annual increase for the longer period as is accorded the shorter period, this would seem to offer an upper limit to the coal-fired capacity additions in the 1973-2000 period of the order of 56,000 megawatts. This implies a greater participation by outside utilities, and a greater export of electric energy than that assumed by the staff."

The Bureau of Power included in its report for the State of Nebraska on future electric generating capacity. 4/

"The following comments and enclosed tables supplement similar data in the Bureau of Power's staff report submitted September 21, 1973. In general, and only with regard to those work group matters requested of the Federal Power Commission staff, the data herewith supplied for Nebraska can stand alone in that it has little effect upon previously supplied data for the four-state area of Montana, Wyoming, North Dakota, and South Dakota.

The electric utilities in Nebraska are members of, or cooperate with, the Mid-Continent Area Reliability Coordination Agreement (MARCA). MARCA is one of the nine Regional Electric Reliability Councils reporting annually to the Federal Power Commission certain aspects of the twenty-year expansion plans or projections. This is in accordance with FPC Order 383-3. The Council, in its September 1, 1973, addendum to its April 1, 1973, submission, reported that 55 percent of the projected 27,000 megawatts of electric generating capacity additions in the 1983-1992 period would be nuclear. It further reported that in 1992, after retirements, 40 percent of the generating capacity in service would be nuclear. The data indicated that the Nebraska area of the Council would generally approximate these trends."

4/ FPC Bureau of Power Staff Report, Nebraska=Future Electrical Generation, OCT. 1973, submitted to the National Energy Considerations Work Group, NGPR.

"The projected growth of installed capacity from 2,271,846 kilowatts to 15,100,000 kilowatts in the 28 year 1972-2000 period is an annual average growth of 7 percent. Projections for Nebraska, however, differ in a significant area from the other four states in the NGPR. It is projected for the year 2000 that 88 percent of the installed capacity will be equally divided between fossil fired steam-electric capacity and nuclear fired steam-electric capacity. Because of current nuclear electric generation construction programs, no significant increase in coal use within the state is foreseen until 1979. The increase in coal consumption thereafter might reasonably be expected to be secured from presently utilized Wyoming sources."

In calculating the coal requirements for electrical generation, the total coal-fired generating capacities for each State were determined and it was assumed that 4.15 million tons of coal were required for each 1,000 megawatt of generating capacity. This explains the differences between the coal requirements forecast and the FPC figures. For oil and gas, the FPC projections were used. (See Appendix II-B, Section A)

The conversion factors and heat rates used in deriving the electrical sector forecast were: Coal, 15,000,000 Btu/ton; natural gas, 1,031 Btu/cu.ft.; petroleum, 6,000,000 Btu/bbl; hydropower, declining heat rate of 10,200 Btu/kwhr to 8,500 Btu/kwhr in 2000; nuclear, declining heat rate of 10,660 Btu/kwhr to 9,000 Btu/kwhr in 2000.

PETROLEUM SUPPLY FORECAST

Table 3 "Northern Great Plains Region-Estimated Petroleum Supply Schedule, 1971 Actual, and Projected to the Year 2000," indicates the estimated production of crude petroleum in the region. In 1971, the Northern Great Plains Region produced 225.8 million barrels (almost three-fourths from Wyoming) equivalent to 4.1 percent of the total national petroleum requirements. Production of petroleum in the region is expected to decline in the future although the outlook is favorable for sustaining moderate production and avoiding a sharp decline. Many areas in the region, particularly in Wyoming, have yet to be adequately explored and tested. The petroleum production is expected to become less significant to the total national requirements in the future, however, with the projected 101 million barrels of petroleum production in the year 2000 being only 0.8 percent of the total U.S. petroleum requirements.

Supplemental petroleum supplies from the region (particularly Wyoming) may come from nonconventional sources as shale oil, tar sands, and coal liquefaction beyond the year 1980, although the development of new technologies as well as the competitive position of these sources will be contributing factors to the extent these new energy forms are made available.

Table 3. Northern Great Plains Region - Estimated Petroleum Supply Schedule 1971 Actual and Projected to the Year 2000

	1971	1975	1980	1985	2000
North Dakota					
Million barrels-----------	23.8	20	19	17	6
Trillion Btu--------------	131.4	110	105	94	33
South Dakota					
Million barrels-----------	0.2	insig.	insig.	insig.	insig.
Trillion Btu--------------	1.3	insig.	insig.	insig.	insig.
Montana					
Million barrels-----------	35.1	33	31	28	18
Trillion Btu--------------	196.9	181	171	154	99
Wyoming					
Million barrels-----------	156.1	136	127	114	75
Trillion Btu--------------	869.0	748	699	627	413
Nebraska					
Million barrels-----------	10.6	5	3	3	2
Trillion Btu--------------	58.8	28	17	17	11
Regional Totals					
Million barrels-----------	225.8	194	180	162	101
Trillion Btu--------------	1,257.4	1,067	992	892	556
Percent of total U.S. requirements------------	4.1	3.0	2.4	1.8	0.8
U.S. Total Requirements 1/					
Million barrels-----------	5,523	6,340	7,715	9,140	12,985
Trillion Btu--------------	30,492	35,090	42,190	50,700	71,380

1/ From U.S. Energy Through the Year 2000, U.S. Department of the Interior.

NOTE: Conversion factor: 5,500,000 Btu per barrel.

NATURAL GAS SUPPLY FORECAST

Table 4, "Northern Great Plains Region-Natural Gas Supply Schedule, 1971 Actual, and Projected to the Year 2000," indicates the estimated future natural gas production of the Northern Great Plains Region by States. Production of natural gas in the region in 1971 was 450.2 billion cubic feet with Wyoming producing over 380 billion cubic feet of this total. This 450.2 billion cubic feet represented 2.1 percent of the total natural gas produced in 1971 in the Nation. In the future it is expected that the States of Montana and North Dakota will sustain their moderate production levels of 1971 suffering only small declines. Wyoming production should fall more significantly although in all three States many areas have yet to be adequately tested and explored and production could possibly rise in the future.

It is estimated that production of natural gas in the Northern Great Plains Region will be 352 billion cubic feet in the year 2000, 1.3 percent of the estimated total national production.

Production of gaseous fuels from coal in the future will be discussed in the following section.

Table 4. Northern Great Plains Region - Natural Gas Supply Schedule 1971 Actual and Projected to the Year 2000

	1971	1975	1980	1985	2000
North Dakota					
Billion cu.ft.--------------------	33.9	32	29	28	26
Trillion Btu---------------------	34.9	33	30	29	27
South Dakota					
Billion cu.ft.--------------------	0	0	0	0	0
Trillion Btu---------------------	0	0	0	0	0
Montana					
Billion cu.ft.--------------------	32.7	31	29	28	25
Trillion Btu---------------------	33.7	32	30	29	26
Wyoming					
Billion cu.ft.--------------------	380.1	340	320	310	300
Trillion Btu---------------------	391.9	351	330	320	309
Nebraska					
Billion cu.ft.--------------------	3.5	2	2	2	1
Trillion Btu---------------------	3.6	2	2	2	1
Regional Totals					
Billion cu.ft.--------------------	450.2	405	380	368	352
Trillion Btu---------------------	464.1	418	392	380	363
Percent of total Domestic Natural Gas Supply--------------	2.1	1.8	1.7	1.6	1.3
Total Domestic Natural Gas Supply [1]					
Billion cu.ft.--------------------	21,150	21,962	22,969	23,837	27,659
Trillion Btu---------------------	21,810	22,640	23,660	24,510	28,350

[1] From U.S. Energy Through the Year 2000, U.S. Department of the Interior.

NOTE: Converted on the basis of 1,031 Btu/cu.ft.

THE SYNTHETIC GAS SECTOR AND SYNTHETIC GAS SUPPLY FORECAST-Intermediate Scenario

The demand for Northern Great Plains coal inputs to the Synthetic Gas Sector, the synthetic gas produced, and the number of plants required are indicated in the following table:

	1985		2000	
COAL INPUTS:	million tons	trillion Btu	million tons	trillion Btu
North Dakota..	15	228	53	796
Montana.......	23	340	45	681
Wyoming.......	15	228	23	340
Total.........	53	796	120	1,817
GAS PRODUCED:	billion cu. ft.	trillion Btu	billion cu.ft.	trillion Btu
North Dakota..	165	149	578	521
Montana.......	248	223	495	446
Wyoming.......	165	149	248	223
Total.........	578	521	1,321	1,190
NUMBER OF PLANTS:				
North Dakota..	2		7	
Montana.......	3		6	
Wyoming.......	2		3	
Total.........	7		16	

By 1980 it is estimated that 700 billion cubic feet of synthetic gas will produced in the United States both from the conversion of petroleum and coal. 1/ However, no synthetic gas is expected to be produced in the NGPR in this year. Therefore, the years 1975 and 1980 have been excluded from the Region's synthetic gas forecast. Nebraska and South Dakota have also been excluded because no synthetic gas production is expected to take place in these States by the year 2000.

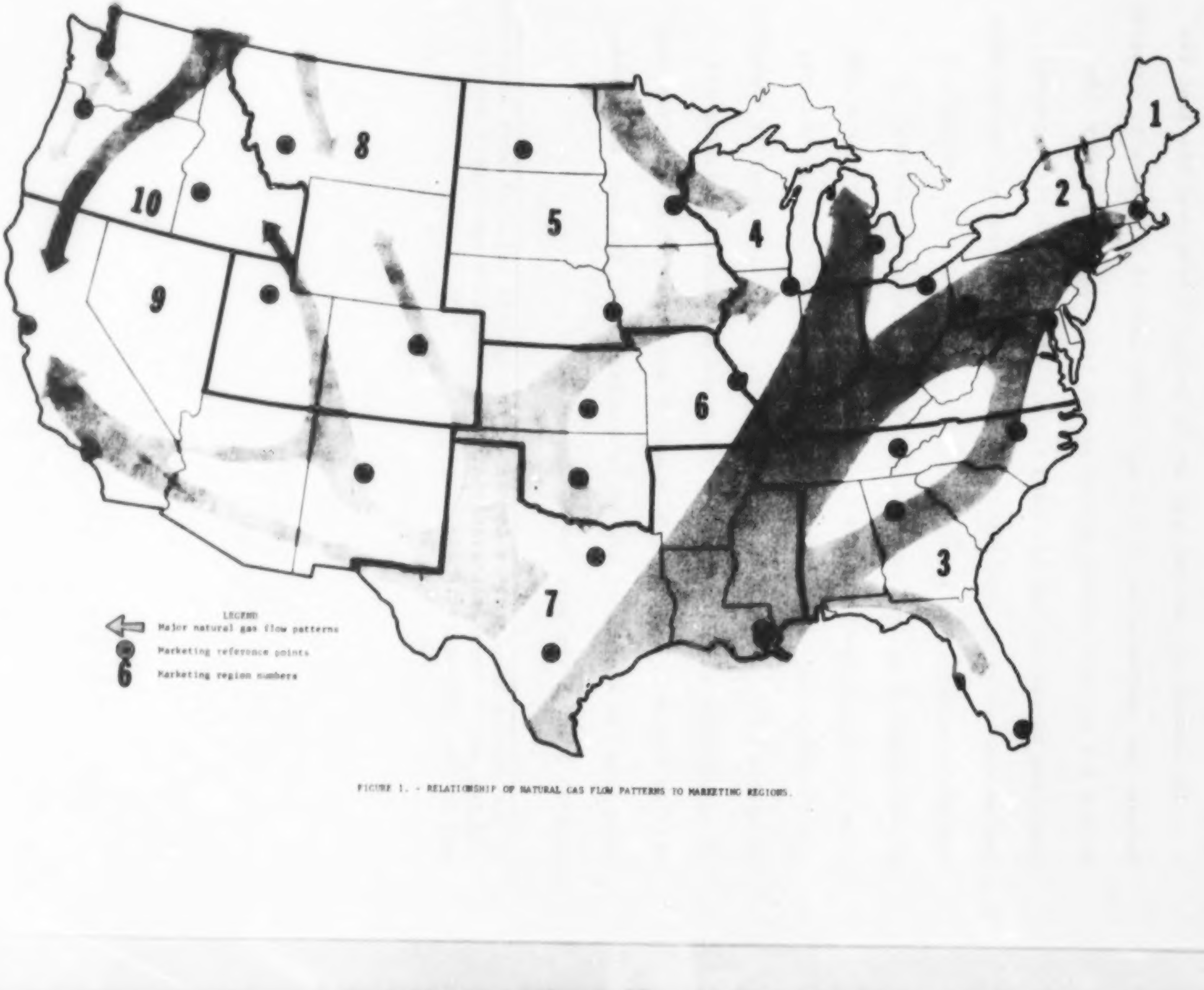
1/ U.S. Energy Through the Year 2000, U.S. Dept. of the Interior, Dec. 1972

The estimated production of synthetic gas in the year 1985 for the United States is 2,000 billion cubic feet. NGPR coal conversion is expected to be 578 billion cubic feet or 26.0 percent of the projected U.S. production. Coal inputs necessary to achieve this production of synthetic in the NGPR will total 53 million tons in 1985.

In the year 2000, the NGPR is expected to supply 1.3 trillion cubic feet of synthetic gas (21.6 percent of the expected total U.S. production of 5.5 trillion cubic feet in the year 2000) Coal inputs required to meet this projected regional production figure in the year 2000 will total 120 million tons.

The coal gasification plants forecast were assumed to have a 250 million cubic feet per day production capacity with a conversion efficiency of 65 percent. Assuming a coal heat value of 15 million Btu per short ton, each plant would require 7.6 million tons of coal per year at full operation.

The only justification for synthetic gas is to make good shortfalls in natural gas. The following discussion will explain the background, on a national and regional level, that led to the above forecast. It is based on a soon-to-be published study by the Branch of Natural Gas, Division of Fossil Fuels, Bureau of Mines. The study is tentatively titled "The Potential Market Availability and Economics of Supplemental Sources of Natural Gas."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LEGEND
Major natural gas flow patterns
Marketing reference points
6 Marketing region numbers

FIGURE 1. - RELATIONSHIP OF NATURAL GAS FLOW PATTERNS TO MARKETING REGIONS.

Source: Branch of Natural Gas, Division of Fossil Fuels, U.S. Bureau of Mines

The demand for natural gas in the United States over the last two decades has increased at an average annual rate of 5.9 percent, compared with a 3.2 percent average annual growth rate for total energy, the marketing of natural gas has been accomplished by a pipeline network system consisting of over 900 thousand miles of gathering, transmission, and distribution lines serving the 48 contiguous States. Figure 1, Relationship of Natural Gas Flow Patterns to Marketing Regions, schematically illustrates the link between the sources of supply and the 10 market regions as designated by the Future (Gas) Requirements Committee (FRC). [2] Regions 1, 2, 3, 4, 6, and 7 are primarily dependent on natural gas supplies from the south and southwest, including the Gulf of Mexico. Regions 5, 8, 9 and 10 are dependent on supplies that flow from the southwest, the Rocky Mountain area, the west and Canada. Regions 5 and 8 includes the NGP.

2/ The Future Requirements Committee through its regional work committees obtains demand forecasts from individual companies who supply natural gas to the various regional markets.

Potential Supply Shortfalls -The Need for Supplements

The rate at which supplies of natural gas are being made available to distributors is not keeping pace with demand. Recently, industrial sales of natural gas have been curtailed and growth in other consumer sectors has been limited. The magnitude and the market areas where future supply shortfalls will occur is difficult to determine. Nevertheless, estimates of potential supply shortfalls are essential in order to assess the needs for supplemental supplies. The technique of "matching" two sets of supply forecasts with two sets of demand projections as shown in Table A, "Relationship of Supply and Demand Forecast," provides a basis for regionalizing and quantifying potential shortfalls. Based on this procedure, a range of potential supply shortfalls for each regional market is shown in Table B, "Potential Shortfalls of Natural Gas Supplies in Regional Markets." In the absence of other methods, "matching" permits a comparison of the relative impact of shortfalls in regional markets. For example, Table B, indicates that the need for supplemental supplies are most acute in Regions 2, 3, 4 and 9 which show an average potential supply deficiency ranging from 2.1 to 4.6 trillion cubic feet by 1990. The remaining regions show a potential unsupplied demand average ranging from 0.2 to 1.6 trillion cubic feet by 1990.

Implicit in the concept of supply shortfalls over the long term is one of the following:

(1) The price of gas at the wellhead will continue to be regulated, and maintained at a level lower than the equilibrium price, i.e., th

Table A.--Relationship of Supply and Demand Forecasts

(trillion cubic feet)

		Market Regions										Total
		1	2	3	4	5	6	7	8	9	10	(Lower 48 States)*
Potential Demand												
1975	FRC 1/	0.33	5.00	2.16	4.22	1.14	1.91	8.50	0.63	3.16	0.48	27.53
	DI 2/	0.29	4.49	1.92	3.83	1.01	1.69	7.35	0.56	2.89	0.43	24.46
1980	FRC	0.40	5.96	2.73	5.22	1.26	2.35	9.80	0.70	3.41	0.57	32.40
	DI	0.33	4.94	2.27	4.33	1.05	1.95	8.13	0.58	2.82	0.47	26.67
1985	FRC	0.49	7.00	3.39	6.31	1.41	2.59	11.62	0.79	3.70	0.66	37.96
	DI	0.38	5.45	2.64	4.90	1.10	2.01	9.06	0.61	2.88	0.51	29.54
1990	FRC	0.60	8.23	4.21	7.61	1.56	2.92	13.93	0.89	4.06	0.75	44.76
	DI	0.44	5.98	3.06	5.53	1.13	2.12	10.12	0.64	2.95	0.54	32.51
1995	FRC	0.75	9.67	5.26	9.23	1.73	3.33	16.79	1.00	4.47	0.84	53.07
	DI	0.50	6.47	3.52	6.17	1.15	2.23	11.24	0.67	2.98	0.56	35.49
2000	FRC	0.92	11.39	6.57	11.18	1.93	3.78	20.17	1.13	4.91	0.95	62.93
	DI	0.56	6.97	4.02	6.83	1.18	2.29	12.34	0.69	3.00	0.58	38.46
Potential Supply												
1975	NPC 3/	0.17	2.56	1.03	1.89	0.60	3.18	9.36	0.91	2.04	0.05	21.79
	FPC 4/	0.16	2.35	0.95	1.74	0.55	2.61	8.94	0.69	1.91	0.04	19.94
1980	NPC	0.18	2.67	1.08	1.98	0.62	3.64	9.52	0.91	2.05	0.05	22.70
	FPC	0.14	2.20	0.88	1.63	0.51	2.26	8.66	0.60	1.75	0.04	18.67
1985	NPC	0.20	2.94	1.18	2.18	0.68	4.64	9.81	1.11	2.18	0.05	24.97
	FPC	0.14	2.11	0.85	1.56	0.49	2.20	8.29	0.59	1.66	0.03	17.92
1990	NPC	0.21	3.22	1.30	2.39	0.75	5.52	10.23	1.30	2.32	0.05	27.36
	FPC	0.14	2.06	0.83	1.52	0.47	2.17	8.05	0.58	1.61	0.03	17.46
1995	NPC	0.23	3.52	1.42	2.60	0.81	6.42	10.80	1.50	2.50	0.06	29.86
	FPC	0.13	2.00	0.81	1.48	0.46	2.01	7.92	0.54	1.60	0.03	16.98
2000	NPC	0.25	3.82	1.54	2.83	0.88	7.34	11.30	1.70	2.74	0.07	32.47
	FPC	0.14	2.01	0.81	1.49	0.47	2.11	7.86	0.57	1.62	0.03	17.11

* Excludes field use.

1/ Future Requirements Committee "Future Natural Gas Requirements of the United States," vol. No. 4, Oct. 1971.

2/ U.S. Dept. of Interior "United States Energy through the Year 2000," Dec. 1972, (interpolated 1990 and 1995).

3/ National Petroleum Council "U.S. Energy Outlook," Dec. 1972 (Supply Case I, Contiguous 48 projected 1985-2000).

4/ Federal Power Commission "National Gas Supply and Demand 1971-1990," Feb. 1972, (projected 1990-2000).

Source: Branch of Natural Gas, Division of Fossil Fuels, U.S.B.M.

Table 3.--Potential Shortfalls of Natural Gas Supplies in Regional Markets

(trillion cubic feet)

Marketing Regions	1975 Low 1/	1975 High 2/	1980 Low	1980 High	1985 Low	1985 High	1990 Low	1990 High	1995 Low	1995 High	2000 Low	2000 High
1	0.1	0.2	0.2	0.3	0.2	0.4	0.2	0.5	0.3	0.6	0.3	0.8
2	1.9	2.7	2.3	3.8	2.5	4.9	2.8	6.2	3.0	7.7	3.2	9.4
3	0.9	1.2	1.2	1.9	1.5	2.5	1.8	3.4	2.1	4.5	2.5	5.8
4	1.9	2.5	2.4	3.6	2.7	4.8	3.1	6.1	3.6	7.8	4.0	9.7
5	0.4	0.6	0.4	0.8	0.4	0.9	0.4	1.1	0.3	1.3	0.3	1.5
6	0	0	0	0.1	0	0.4	0	0.8	0	1.3	0	1.7
7	0	0	0	0.1	0	3.3	0	5.9	0.4	8.9	1.0	12.3
8	0	0	0	0.1	0	0.2	0	0.3	0	0.5	0	0.6
9	0.9	1.3	0.8	1.7	0.7	2.0	0.6	2.5	0.5	2.9	0.3	3.3
10	0.4	0.4	0.4	0.5	0.5	0.6	0.5	0.7	0.5	0.8	0.5	0.9
Total	6.5	8.9	7.7	12.9	8.5	20.0	9.4	27.5	10.7	36.3	12.1	46.0

1/ Low shortfall based on DI demand minus NPC Case I supply.
2/ High shortfall based on FRC demand minus FPC supply.

Source: Branch of Natural Gas, Division of Fossil Fuels, U.S.B.M.

price where supply and demand are in equilibrium. The result would be shortfalls in natural gas that would have to be supplemented from other higher priced, nonregulated, sources, or

(2) The price of gas is deregulated, and rises to such a level that provision of supplemental supplies becomes profitable.

In either event supplemental supplies would be necessary. However, natural gas wellhead prices could be deregulated, and the result could be an increase in both price and supply. In this instance the resulting equilibrium level of supply and demand could be at a price sufficiently low to eliminate the necessity for supplementation of natural gas supplies.

There have been various econometric models examining the supply-price relationship in the natural gas industry. Two of the earliest were by Harold Wein and J. Harvey Edmonston of the Federal Power Commission. 3/ The results were essentially the same in both instances, i.e., they both concluded that the higher the FPC allowed wellhead prices to rise, the smaller would be future gas supply additions. Two later models by J. Daniel Khazzoom 4/ and by Edward W. Erickson and Robert M. Spann. 5/ Neither model produced any results useful in

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3/ These models are discussed in detail in a book by Joe L. Steele, "The Use of Econometric Models by Federal Regulatory Agencies."

4/ Khazzoom, J. Daniel. "The FPC Staff's econometric model of natural gas supply in the United States." Bell Journal of Economics and Management Science, Spring 1971.

5/ "Supply Response in a Regulated Industry: The Case of Natural Gas," Bell Journal of Economics and Management Science, Spring, 1971.

evaluation of the price elasticity of supply of natural gas reserves. The final model discussed is by Paul W. MacAvoy and Robert S. Pindyck.[6/] This is the only model to examine the simultaneous interaction of supply and demand. Their preliminary conclusions are summarized in the following quotation:

> "Following a strategy of well-publicized price increases, the Federal Power Commission can eliminate the domestic gas shortage by 1980. The best of the (feasible) price changes would be 3 cents per annum. In contrast, 1 cent per annum would eliminate the entire stock of domestic reserves, and 5 cents per annum would not be maintainable in the markets for gas because there would be a veritable flood of additional discoveries relative to additional production demand. The 3 cent per annum increase would "find" enough gas while restraining demands for a domestic 12:1 reserve-to-production ratio -- close to that before the shortage. The resulting level of wholesale prices would be less than that which would occur under a continuation of the present ceilings and importation of liquified gas at $1.15 per Mcf."

If true, this would seem to indicate that the correct answer to the natural gas shortage is deregulation, and not the provision of supplementary supplies. The following discussion thus implicitly indicates continued regulation of wellhead prices.

Proximity of Supplemental Supplies to Regional Markets

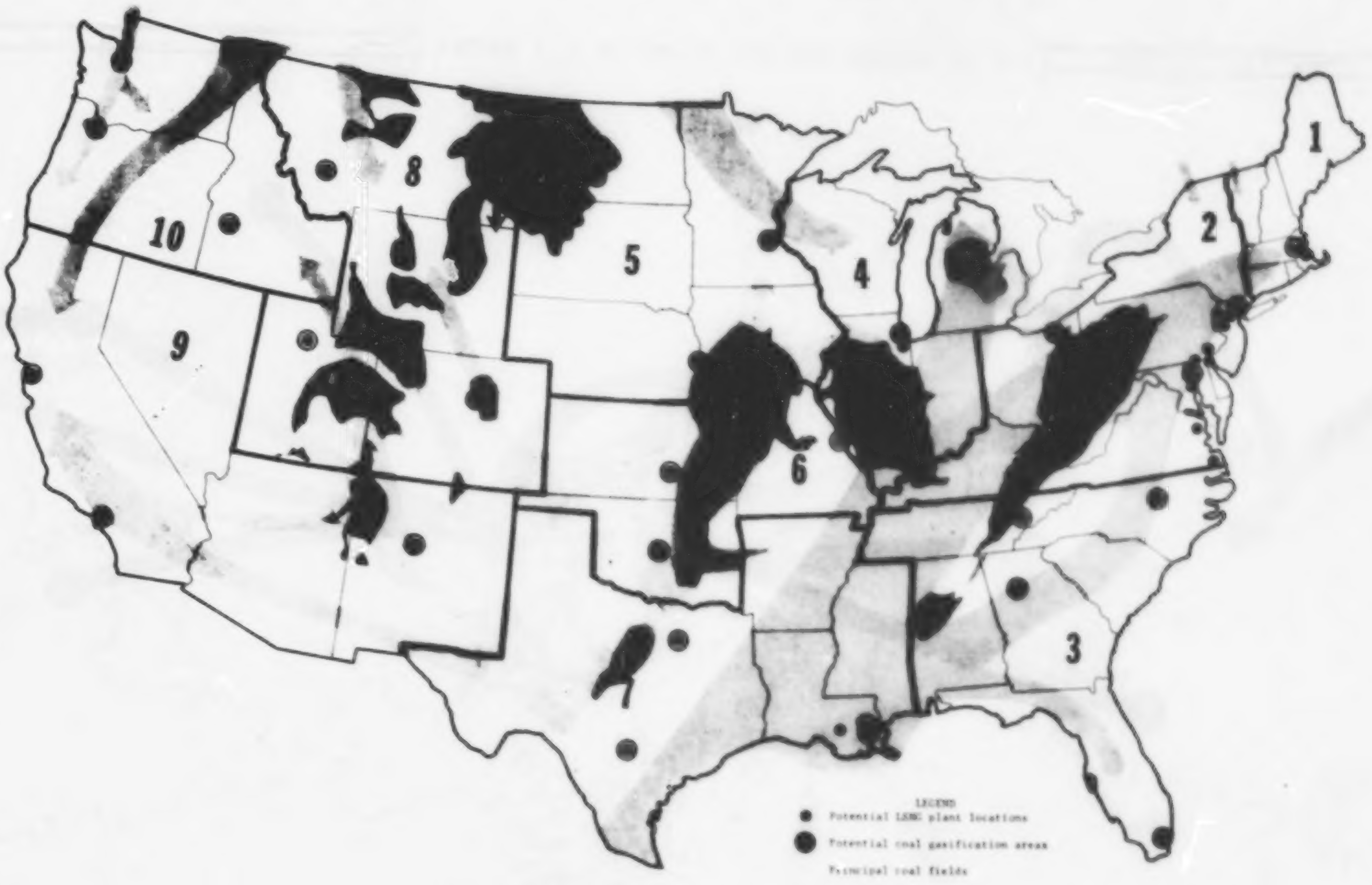
The prospects of supplemental supplies satisfying unfulfilled demands depend on the accessibility and cost of such supplies in regional markets.

The accessibility of various sources of supplemental supplies to regional markets depends on the location of plant sites which manufacture gaseous fuels, the terminal locations and border crossings where imported natural gas is delivered and where new sources of domestic natural gas is found.

[6/] "An Econometric Policy Model of Natural Gas" Massachusetts Institute of Technology, Cambridge, Mass. Dec. 1972.

The prospective sites of coal-synthetic natural gas (CSNG) and liquid-synthetic natural gas (LSNG) plants are schematically illustrated in Figure 2, "Potential Locations of CSNG Plants and LSNG Plants." Figure 2 also shows the relationship of the natural gas flow patterns, and the regional markets to such plant sites. The siting of CSNG plants is determined by the location of suitable coal deposits and the availability of attendant facilities amenable to coal gasification technology. The coal deposits suitable for gasification are located in FRC Market Regions 2, 4, 5, 8 and 9 (where 5 and 8 include the NGP). The accessibility of CSNG beyond the indigenous sources of supply depend on the distribution support system. The use of existing natural gas pipeline systems to distribute CSNG would confine the availability of CSNG from eastern coals to Regions 1, 2, 4 and possibly 3 and 6. CSNG produced from western coal deposits would be deliverable to markets 5, 8, 9 and 10. Basically, this implies that gas produced from NGP coal could move south and west, with some eastward movement internally in Region 5. The American Gas Association has estimated that there are 176 potential CSNG plant sites; assuming each has a producing capacity of 250 million cubic feet. An estimated 50 percent are located west of the Mississippi River.

The LSNG plants usually will be located near or at the market sites, as shown in Figure 2. Therefore, LSNG needs for a distribution system to enhance access to markets is not significant. The primary consideration in selecting an LSNG plant site is its proximity to port facilities and domestic petroleum refineries, from which the plant may have access to imported or domestic feedstocks. LSNG plants will not be a factor in the NGP, but will have an impact on Regions 9 and 10 markets for NGP coal and gas.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LEGEND
Potential LSNG plant locations
Potential coal gasification areas
Principal coal fields

FIGURE 7. - POTENTIAL LOCATIONS OF CSNG PLANTS AND LSNG PLANTS.

Source: Branch of Natural Gas, Div. of Fossil Fuels, U.S.B.M.

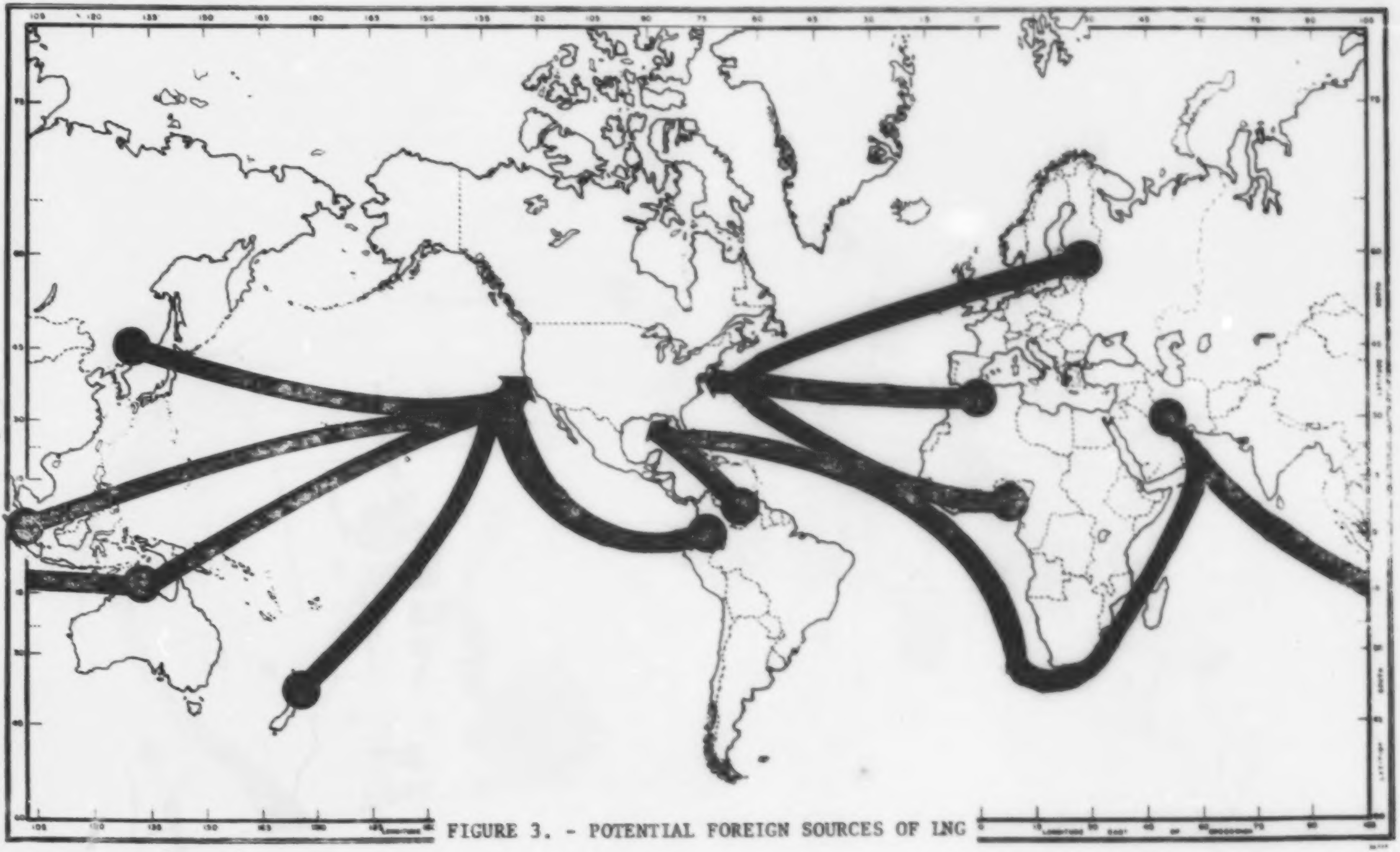


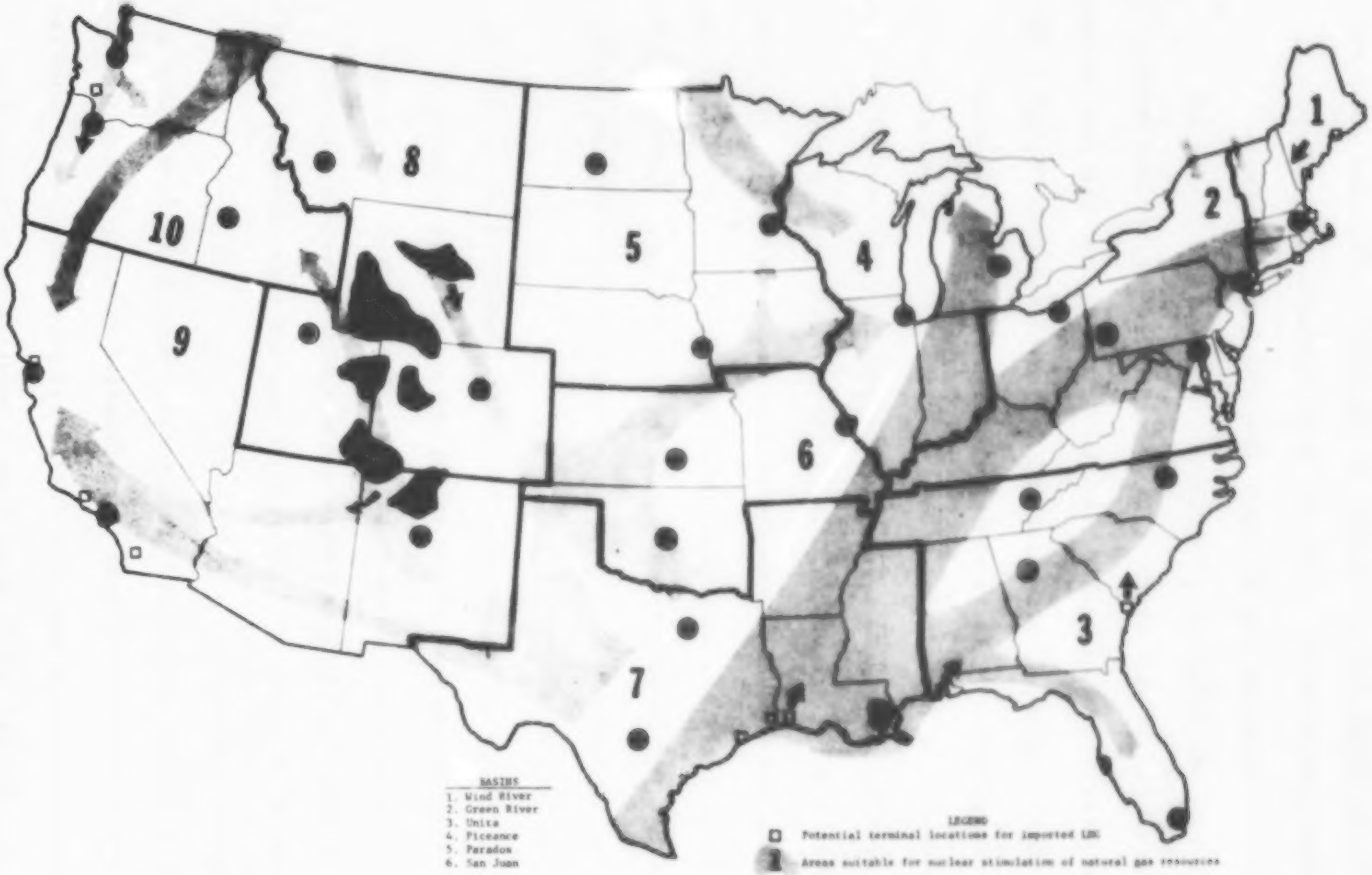
FIGURE 3. - POTENTIAL FOREIGN SOURCES OF LNG

Source: Branch of Natural Gas, Div. of Fossil Fuels, U.S.B.M.

The potential foreign sources of liquefied natural gas (LNG) and the prospective receiving ports are shown schematically in Figure 3, "Potential Foreign Sources of LNG." The proposed and potential locations of LNG terminals along the Pacific, Gulf of Mexico and Atlantic Coast, as well as the sites prospective for nuclear stimulation and the relationship of such facilities to the natural gas flow pattern, are shown in Figure 4, "Potential LNG Terminals and Areas Suitable for Nuclear Stimulation." The potential foreign sources of LNG supplies are assumed to be nations which have sufficient supplies of natural gas to sustain exports equivalent to 300 million cubic feet of gas per calendar day for a period of 20 to 25 years, have suitable port facilities, and nominal internal demand relative to supply. The potential LNG terminal ports are in coastal Regions 1, 2, 3, 7, 9 and 10. Regions 9 and 10 are, of course, market areas for NGP coal gas. LNG supplies could utilize existing natural gas flow patterns to market LNG beyond the market terminals.

The location of natural gas reservoirs identified as suitable for nuclear stimulation are located in Regions 8 and 9, as shown in Figure 4. Natural gas produced with the aid of nuclear stimulation and using existing pipeline transmission systems, could be marketed in Regions 5, 8, 9 and 10 - which again are the same markets that NGP coal gas could supply.

The potential routes for transporting natural gas from Alaska and Canada via a supply integrated trans-Canadian pipeline system are shown schematically on Figure 5, "Potential Supply Routes for Canadian and Alaskan Natural Gas." Also shown schematically in Figure 5 is the proposed route to transport North Slope Alaska natural gas via a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BASINS
1. Wind River
2. Green River
3. Uinta
4. Piceance
5. Paradox
6. San Juan
LEGEND
□ Potential terminal locations for imported LNG
▨ Areas suitable for nuclear stimulation of natural gas resources

FIGURE 4. - POTENTIAL LNG TERMINALS AND AREAS SUITABLE FOR NUCLEAR STIMULATION

Source: Branch of Natural Gas, Div. of Fossil Fuels, U.S.B .M.

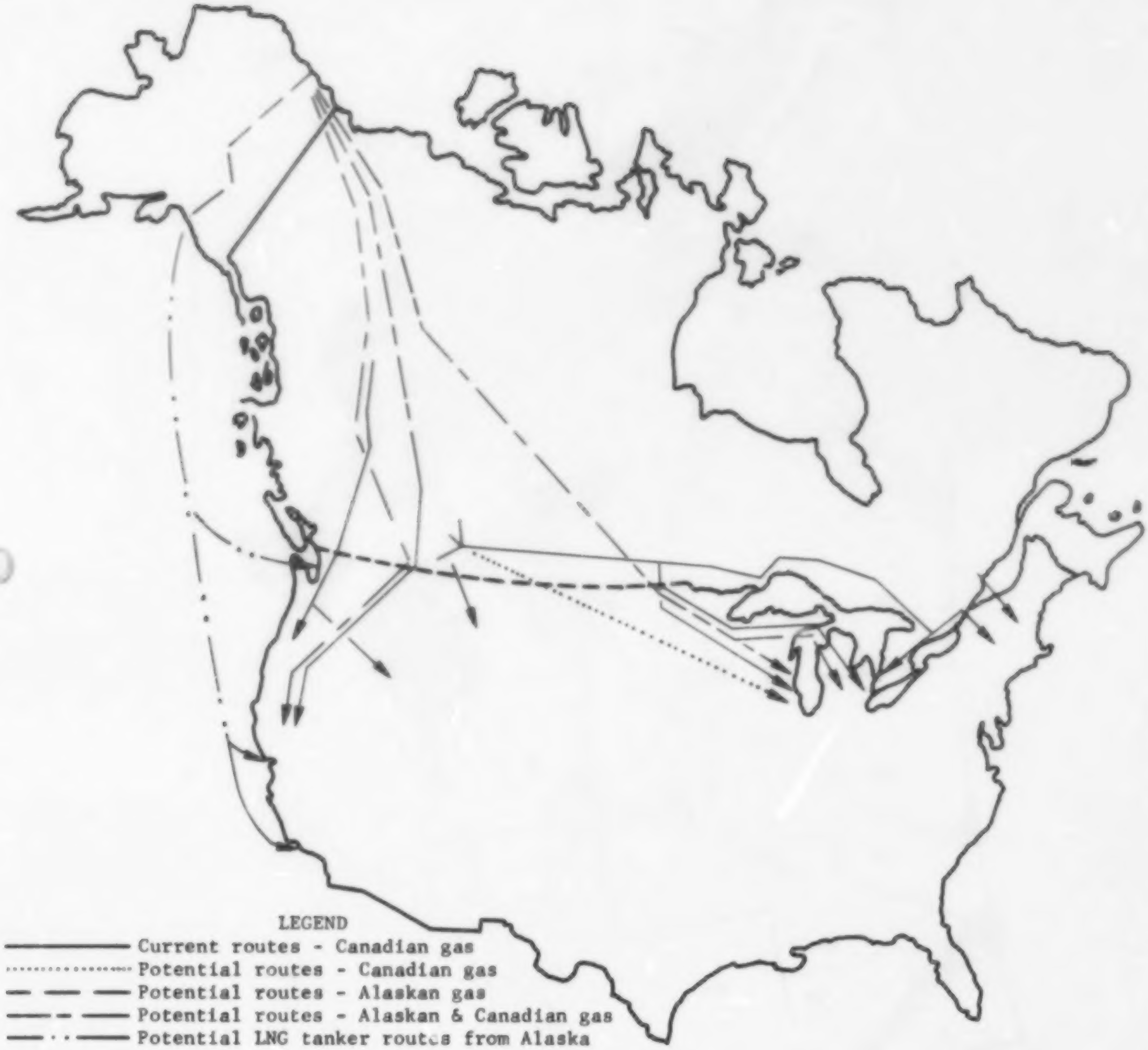
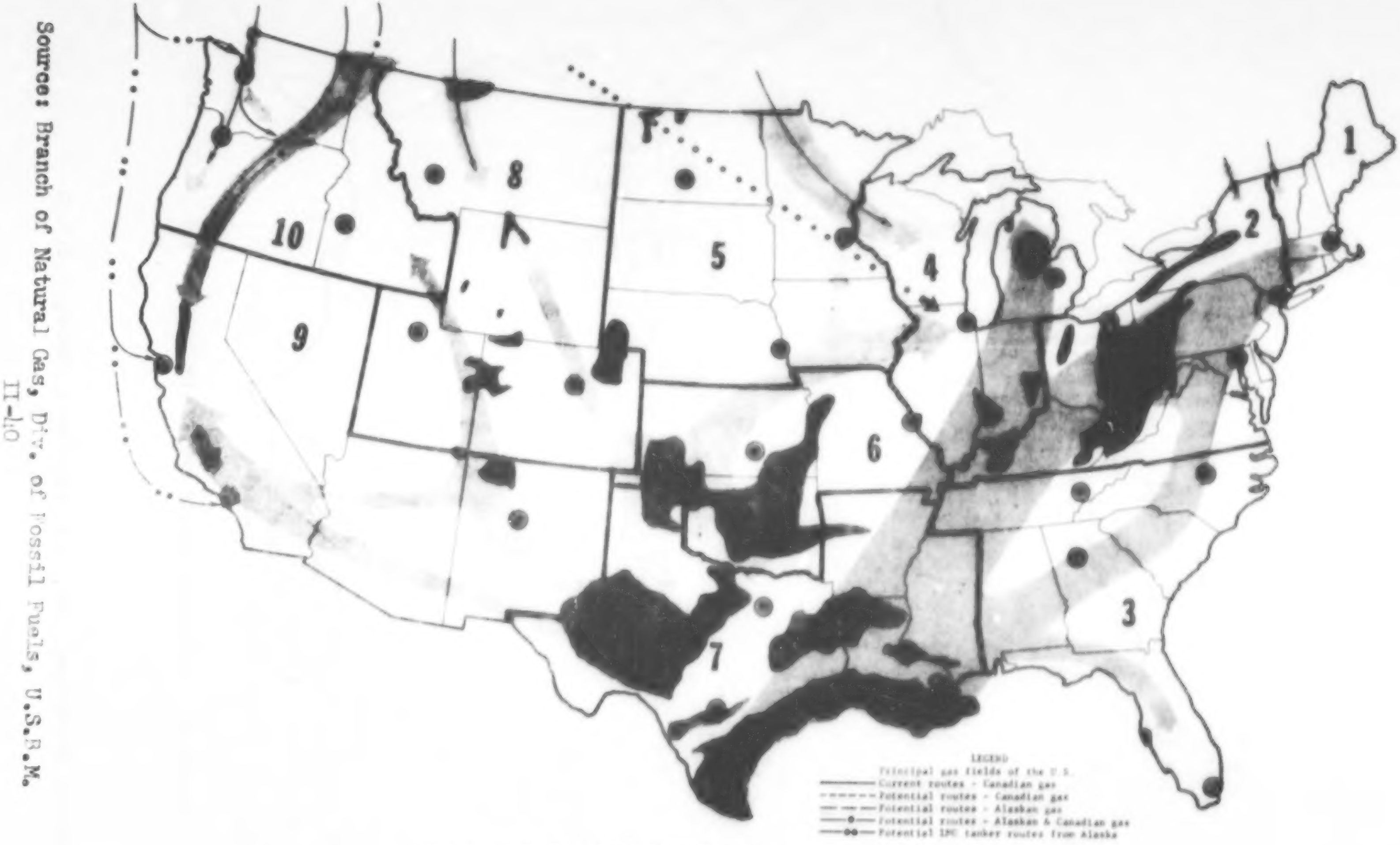

LEGEND
Current routes - Canadian gas
Potential routes - Canadian gas
Potential routes - Alaskan gas
Potential routes - Alaskan & Canadian gas
Potential LNG tanker routes from Alaska

FIGURE 5. - POTENTIAL SUPPLY ROUTES FOR CANADIAN AND ALASKAN NATURAL GAS.

Source: Branch of Natural Gas, Div, of Fossil Fuels, U.S.B.M.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LEGEND
Principal gas fields of the U.S.
Current routes - Canadian gas
Potential routes - Canadian gas
Potential routes - Alaskan gas
Potential routes - Alaskan & Canadian gas
Potential LNG tanker routes from Alaska

FIGURE 6. - LOCATION OF U.S. NATURAL GAS FIELDS AND CURRENT AND POTENTIAL NEW SUPPLIES FROM CANADA AND ALASKA.

Source: Branch of Natural Gas, Div. of Fossil Fuels, U.S.B.M.

combination of a trans-Alaskan pipeline and LNG tanker delivery system to U.S. West Coast terminals. The flow of Canadian and Alaskan supplies across the U.S. western and central borders is shown in Figure 6, "Location of U.S. Natural Gas Fields and Current and Potential New Supplies from Canada and Alaska." A historical pattern exists for marketing natural gas supplies across northern U.S. borders. The availability of additional supplies from the Canadian western provinces, and new supplies from the combined sources of Alaska's North Slope and Canada's Mackenzie River Delta (and possibly the Arctic Islands) could result in a greater reliance on Canadian supplies in Regions 4 and 5. In total, Canadian and Alaskan supplies could furnish natural gas to Regions 1, 2, 4, 5, 8, 9 and 10. The last four of these constitutes the market for NGP coal gas. Although not illustrated in Figures 5 and 6, Canadian Atlantic continental shelf prospects (Sable Island) could provide natural gas supplies to Regions 1 and/or 2. LNG deliveries from Alaska could be marketed in Regions 9 and 10 - again, a market area for NGP coal gas.

The Potential Price and Sources of Supplemental Supplies to Regional Markets

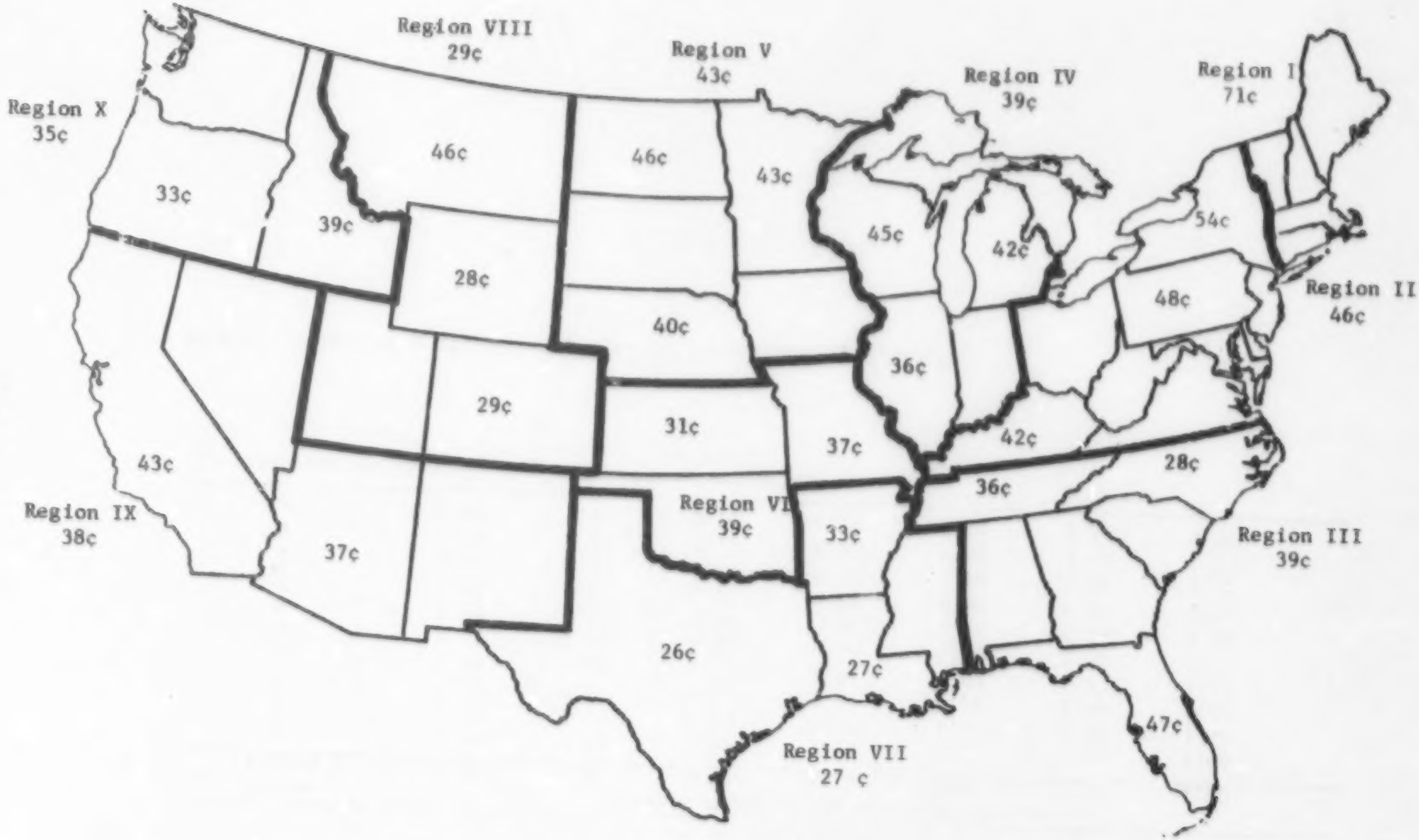
The quantities of supplemental supplies available to regional markets will depend on the committment of capital necessary to develop supplies and supply delivery systems and the subsequent cost in the market. The potential wholesale regional price of supplemental supplies is based on the product price at the U.S. source point and the cost of transporting such supplies to the various regional markets. Table [illegible]

Table C.--Potential Wholesale Regional Prices of Supplemental Supplies
(1972 dollars per million Btu)

Potential Sources of Supplies 1/	Price Range at the Source	Market Regions 1	2	3	4	5	6	7	8	9	10
1. Coal gasification (CSNG)											
a. Western coal	0.85-1.02	1.46-1.63 2/	1.22-1.39 2/	1.25-1.42 5/	1.08-1.25 2/	1.10-1.27	1.04-1.21 2/	0.97-1.16 2/	0.91-1.08	1.04-1.21	0.96-1.13
b. Eastern coal	1.03-1.19	1.24-1.40	1.10-1.26	1.17-1.33	1.11-1.27	1.24-1.40	1.27-1.43	1.17-1.33	1.34-1.50 2/	1.52-1.68 2/	1.26-1.42 2/
2. Gasification of Liquid fuels (LSNG)											
a. Base load supply	1.40 3/	1.40	1.40	1.40	1.40	4/	1.40	1.40	4/	4/	1.40
b. Peak load supply	3.43 3/	3.43	3.43	3.43	3.43	4/	3.43	3.43	4/	4/	3.43
3. Liquified natural gas (LNG)											
a. Region 1	1.40	1.55	1.56 2/	1.57 2/	1.49 2/	1.66 5/	1.69 2/	1.56 2/	1.75 5/	1.93 2/	1.64 5/
b. Region 2	1.15	1.46	1.29	1.21	1.28 2/	1.61 5/	1.37 2/	1.25 2/	1.47 5/	1.63 2/	1.39 5/
c. Region 3	1.10	1.61	1.26	1.16	1.23 5/	1.36 5/	1.32 5/	1.20 2/	1.42 5/	1.58 5/	1.34 5/
d. Region 7	1.05	1.49	1.29	1.19	1.24	1.35	1.22	1.09	1.34 2/	1.47	1.28 2/
e. Region 9	1.45	2.30 2/	2.01 2/	2.07 5/	1.85 2/	1.97 5/	1.85 2/	1.64 2/	1.67 2/	1.50	1.47 2/
f. Region 10	1.45	2.30 5/	2.01 5/	2.07 5/	1.85 5/	1.97 5/	1.85 5/	1.64 2/	1.67 5/	1.50	1.47
4. Nuclear stimulation of natural gas reservoirs (NSG)	0.61-0.80	1.21-1.40 2/	0.98-1.17 2/	1.02-1.21 5/	0.86-1.03 2/	0.86-1.05	0.80-0.99 2/	0.73-0.92 2/	0.67-0.86	0.80-0.99	0.73-0.92
5. Natural gas supplies from Alaska & Canada											
a. North Slope & Mackenzie Delta supplies											
1. U.S. Western border	0.85	1.70 5/	1.41 5/	1.47 5/	1.25 2/	1.37	1.25 2/	1.16 2/	1.07	0.90	0.87
2. U.S. Central border	0.95	1.52	1.29	1.35 5/	1.15	1.16	1.16 2/	1.08 2/	0.98 5/	1.17 5/	1.06 5/
b. Alberta Canada supplies	0.45	1.30 5/	1.01 5/	1.07 5/	0.85 2/	0.97	0.85 2/	0.64 2/	0.67	0.50	0.47
c. Combination trans-Alaska pipeline-LNG tanker	1.20	2.05 5/	1.76 5/	1.82 5/	1.60 5/	1.72 5/	1.60 5/	1.39 5/	1.42 2/	1.25	1.22

1/ Potential penetration of supplies into regions. However, there is little to no probability of transcontinental movement of supplies.
2/ Direction of flow is contrary to existing flow patterns. The utilization of existing transportation facilities not probable.
3/ No transportation considered; plants located within market regions.
4/ No plants proposed for these regions.
5/ No existing flow pattern.

Source: Branch of Natural Gas, Div. of Fossil Fuels, U.S.B.M.


Region X
35¢
Region VIII
29¢
Region V
43¢
Region IV
39¢
Region I
71¢
Region II
46¢
Region III
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Region VI
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Region VII
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Figure 7.--1971 Wholesale Prices by Marketing Regions
in 1972 ¢/Mcf

Source: Branch of Natural Gas, Div. of Fossil Fuels, U.S.B.M.

"Potential Wholesale Regional Prices of Supplemental Supplies" provides estimates of wholesale prices of supplemental supplies in regional markets. Particular attention should be paid to Note 2, which indicates the lack of transference of supplies between regions. A useful benchmark for comparing the significance of the potential wholesale prices shown in Table 2 is the current wholesale price of natural gas in regional markets. Figure 7, "1971 Wholesale Prices by Marketing Regions in 1972 ¢/Mcf," shows the approximate range of wholesale prices in the ten regional markets. The potential wholesale regional prices of supplemental supplies, with the exception of Alberta natural gas in Regions 8, 9, and 10, range from nearly 2 to 4 times greater than the current natural gas wholesale prices. The differential between the wholesale price of supplemental supplies and natural gas will decline if natural gas wellhead prices are increased. Table D , "The Effect of Natural Gas Wellhead Prices on Regional Wholesale Prices," is an approximation of the effect of varying wellhead prices on the regional prices for natural gas. On the basis of the most economical supplemental supplies available to each region as shown on Table D , it appears that natural gas wellhead prices could range from $0.60 to $1.00 per MMBTU to be at parity with supplemental sources. The parity range may be reduced to $0.80 to $1.00 by excluding the potential availability of nuclear stimulated natural gas supplies.

The following describes the most significant source of supplemental supplies most likely to penetrate each regional market and the potential wholesale price of such supplies.

Market Region	Primary Supplemental Supply	EWP 1/ range $/per MMBTU
1	CSNG 2/	1.24 - 1.40
	LNG 3/	1.40
2	CSNG	1.10 - 1.26
	LNG	1.29
	LSNG 4/	1.40 - Peak Load 3.43 - Base Load
3	LNG	1.16 - 1.19
	CSNG	1.17 - 1.33
4	CSNG	1.08 - 1.27
	ACNG 5/	1.15
5 #	CSNG	1.10 - 1.40
	ACNG	0.97 - 1.37
6	NSG 6/	0.80 - 0.99
	CSNG	1.04 - 1.43
7	LNG	1.09
	LSNG	140 (pl) - 3.43 (bl)
8 #	NSG	0.67 - 0.86
	CSNG	0.91 - 1.08
	ACNG	0.67 - 1.07
9 ##	CSNG	1.04 - 1.21
	ACNG	0.50 - 1.25
	NSG	0.80 - 0.99
	LNG	1.50
10 ##	ACNG	0.47 - 1.22
	CSNG	0.96 - 1.13
	NSG	0.73 - 0.92
	LNG	1.47

1/ Estimated wholesale price.
2/ Coal - synthetic natural gas.
3/ Liquefied natural gas
4/ Liquid - synthetic natural gas.
5/ Alaska - Canada natural gas.
6/ Nuclear stimulated gas.

# Includes NGP
## Principle markets for coal gas from NGP

Source: Branch of Natural Gas, Div. of Fossil Fuels, U.S.B.M.

Table E.--Estimated Generalized Transportation Costs

(¢ per Mcf)

Source	Location NPC Supply Region No.	Market Regions 1	2	3	4	5	6	7	8	9	10
Coal gasification (CSNG)											
Montana plants	4	57*	34*	40**	20	21	19	13*	3	22	11
N. Mexico plants	3	64*	39*	41**	26*	30*	19*	11*	9	16	12
Illinois plants	9	27	9	10*	6	17	18*	11*	28*	45*	22**
W. Virginia plants	10	16	5	17*	9	27*	29*	16*	35*	53*	24**
Nuclear stimulation											
Wyoming basins	4	57**	34**	40**	20	21	19	13*	3	22*	11*
Colo./Utah/4 corners	3	64*	39*	41**	26*	30*	19*	11*	9	16	12*
Liquified natural gas (LNG)											
New England terminals	10	16	5	17*	9*	26*	29*	16*	35*	53*	24**
Central Atlantic Coast	11	31	14	6	13*	26*	22*	10*	32*	48*	24**
Gulf Coast terminals	6	44	24	14	19	30	17	4	29**	42**	23**
Pacific Coast terminals	2	85*	56*	62*	40**	52**	40*	19*	22**	5	2
Natural gas producing areas											
Appalachian	10	16	5	17	9	26*	29*	16*	35*	53*	24**
Michigan Basin	8	27	11	26*	10	27*	32*	18*	36*	54*	24**
E. Interior Basin	9	27	9	10*	6	17	18*	11*	28*	45*	22**
Mid-Continent	7	46	24	22**	14	14	13	6	15	31	17*
Gulf Coast	6	44	24	14	19	30	17	4	29**	42**	23**
Permian Basin	5	68	42	42**	28	35	21	9	15	17	14*
East Rocky Mt.	4	57**	34**	40**	20**	21	19	13*	3	22	11*
West Rocky Mt.	3	64*	39*	41**	26*	30*	19*	11**	9	16	12
Pacific Coast	2	85*	56*	62**	40*	52**	40*	19**	22*	5	2

* Direction of flow contrary to existing flow patterns. The utilization of existing transp. facilities not probable.
** No existing flow pattern from source to market region.

Source: Based on FPC estimated 1970 transportation cost of natural gas from NPC production region to FRC market region.

Source: Branch of Natural Gas, Div. of Fossil Fuels, U.S.B.M.

Table F.--Potential Supplies of Gaseous Fuels 1/

(Quadrillion Btu)

Sources	1975	1980	1985	1990	2000
Liquid gasification	0.2 2/-0.8 3/	0.3-1.1	0.5-1.5	NA 4/	NA 4/
Coal gasification	0-0	0.3-0.3	1.1-2.6	2.6-6.8	5.6-15.7
LNG	0.1-0.1	0.9-1.8	2.2-4.5	3.0-5.9	3.8-7.6
Nuclear stimulation	0-0	0.1-0.1	0.7-0.7	1.6-1.6	2.9-2.9
Alaska-Canada	1.2-1.3	2.5-3.0	3.4-4.1	5.5-6.3	6.5-7.4
Subtotal	1.5-2.2	4.1-6.3	7.9-13.4	13.2-22.1	19.3-35.1
Lower 48 Natural gas	21.4-23.5	19.7-24.2	18.7-26.2	18.1-28.3	17.5-33.2
Grand Total	22.9-25.7	23.8-30.5	26.6-39.6	31.3-50.4	36.8-68.3

NA Not Available.
1/ Based on scenarios discussed under the supplement sources sections.
2/ Operating 330 days per year.
3/ Operating 100 days per year.
4/ For total in 1990 & 2000 assume 1985 production rate.

Source: Branch of Natural Gas, Div. of Fossil Fuels, U.S.B.M.

The costs added to source prices in order to establish an estimated wholesale price is shown in Table E , "Estimated Generalized Transportation Costs." Table does not imply that supplies would be transported between the various points shown, but merely provides an approximate unit cost. Based on national averages, in those instances where the direction of flow is contrary to existing flow patterns some escalation of transportation costs must be made.

Quantities of Supplemental Supplies Available

The availability of potential sources of supplemental gaseous fuel supplies will require the importation of foreign oil and gas resources, and the use of domestic oil and coal resources at less than direct use efficiency. The level of supply available from each source will depend on the committment of capital, the successful achievement of research goals, trade alliances, and resolution of environmental objectives.

Table F , "Potential Supplies of Gaseous Fuels," shows the gaseous fuels prospectively available from various supplemental sources based on the supply scenarios discussed under the appropriate sections. The practicability of such estimates must be evaluated independently. The political and environmental ramification of such supply expectations are not considered.

Capital Requirements

Capital requirements are presented in two ways. Table G presents both the estimated capital requirements for 250 trillion Btu annual capacity as well as the likely time of realizing that capacity. Gasification of liquid fuels is the least costly of these four alternatives to natural gas. Nuclear stimulation is the most capital intensive with this presentation.

Table H summarizes the cumulative cost estimates for achieving an additional 3 trillion cubic feet of annual capacity in 1990. (This is considered compatible with achievement of approximately 2 trillion cubic feet by the middle 1980's.) It considers three types of costs instead of one. It starts with the total cumulative capital costs. To these are added the estimated cumulative operating costs. These total identified costs are then discounted at 12 percent. (Other discount-rate presentations are in an appendix.) All the identified costs between now and 1990 are included. Five alternative sources to natural gas are presented as well as estimates for natural gas from the Lower 48.

Table H also ranks the alternatives from the most costly to least costly. LSNG-Naphtha is 7 to 9 times as costly as Natural Gas-Lower 48. The next three alternatives are roughly the same costs, at 4 times as costly as Natural Gas-Lower 48. If nuclear stimulation is both technologically feasible and consumer acceptable, then its costs are roughly those of Natural Gas-Lower 48.

Table G.--Capital Investments for Supplemental Supplies of Gaseous Fuels 1/
(For each average annual delivery capacity of 250 trillion Btu)

Source of Supply	Total Capital Investment (million 1972 dollars)	Realization of Capacity To Produce 250 MMBTU Annually
Coal gasification 2/	760	1976-1980
Gasification of liquid fuels 3/	370	1976-1980
Liquefied natural gas 4/	650	1976-1980
Nuclear stimulation 5/	890	1980-1985

1/ Base load supplies.
2/ Based on plant units with capacity of 250 MMCF/day.
3/ Based on plant units with capacity of 100 MMCF/day.
4/ Excludes foreign field exploration and development, pipeline, and liquefaction plant costs Investment required for foreign liquefaction facilities would be approximately $200 million.
5/ Incremental cost of utilizing nuclear devices.

Source: Branch of Natural Gas, Div. of Fossil Fuels, U.S.B.M.

Table H

Ranking of Alternative Source Costs Through To 1990
For Achieving An Additional 3 Trillion Cubic Feet of Annual Capacity in 1990

Systems	Capital Costs ($ billions)	Total Identified Costs (Capital & Operating) ($ billions)	Total Costs Discounted at 12% ($ billions)	Costs Relative to NG-Lower 48[1]	
				Nominal C&O	Discounted C&O
LSNG-Naptha	4.2	38.8	13.3	6.9	8.9
CSNG-Deep Coal	12.0	22.4	6.3	4.0	4.2
LNG-Tanker	7.0	20.1	6.0	3.6	4.0
CSNG-Surface Coal	10.7	18.9	5.4	3.4	3.6
Nuclear Stimulation	5.0	5.0	1.3	.9	.9
Natural Gas-Lower 48	5.0	5.6	1.5	1.0	1.0

Each system's costs are divided by the costs of Natural Gas-Lower 48 in order to produce a "unit of account"

Source: B ranch of Natural Gas, Div. of Fossil Fuels, U.S.B.M.

Summary

Coal gasification is an expensive alternative to conventional natural gas. The primary markets for NGP coal gasification plants have the possibility of securing supplies from other sources at less cost. The economic viability of NGP coal gasification is thusly inversely related to the economic and technical feasibility of the alternatives.

THE INTERMEDIATE COAL SUPPLY FORECAST

The demand for NGPR coal under the Intermediate Forecast is illustrated in tables 5 and 6 , in both short tons and energy equivalents, respectively. As shown, demand for coal from the NGPR is expected to rise from 21.3 million tons in 1971 to 362 million tons in the year 2000.

The significance of this production to the future national energy requirements is demonstrated in the following tabulation:

	1971	1975	1980	1985	2000
Intermediate Scenario					
NGP Coal Production:					
Million tons------------	21.3	52	107	192	362
Trillion Btu------------	527.2	798	1,621	2,881	5,436
Total U.S. Energy Requirements 1/					
Trillion Btu------------	68,989	80,265	96,020	116,630	191,900
NGP Coal as Percent of U. S. Energy Requirements-	0.8	1.0	1.7	2.5	2.8

1/ U. S. Energy Through the Year 2000, U.S. Dept. of the Interior, 1972.

Methodology:

The Intermediate Coal Supply Forecast does not account for the effects on energy use of possible sharp increase in the price of energy to consumers. It is possible that prices, which in some cases fell in real terms until about 1970, will in fact rise dramatically, damping the exponential increases in energy demand otherwise forecast. Economic studies of energy price impacts suggest, but only suggest, that total energy demands might actually level off if this happens. 1/

1/ See, for example, the NSF-RANN study done by Chapman, Tyrrell, and Mount as summarized in Science, Vol. 178, No. 4062, Nov. 17, 1972, pp. 703-708. There is substantial controversy over their results.

Electrical Generation Sector:

See Electrical Sector Forecast-Intermediate Scenario, Page II-15.

Synthetic Gas Sector:

See Synthetic Gas Forecast, Intermediate Scenario, Page II-2[illegible].

Export Sector: 2/

For the years 1975 and 1980 the existing and near future contracts for out-of-region coal shipments were examined and reconciled with mining company projections (from Mineral Resources Work Group report, NGPR) of total production to determine the level of exports from the individual States.

Since demand for NGP coal in the export sector is expected to come from electrical generation, for the years 1985 and 2000 the export sector for NGP coal was broken down into four major market areas: (1) South Dakota and Nebraska, (2) the MAIN Regional Electric Reliability Council Area, (3) the SWPP Regional Electric Reliability Council Area, and (4) the non-Northern Great Plains States MARCA-WSCC Regional Reliability Council area. See the map on page II-57 for the geographical location of these market areas.

The following forecast was used to determine the level of exports to each area, except the South Dakota-Nebraska area, for which demand has been previously determined:

2/ The export sector discussion is based, in part, on section B of Appendix II-B.

Projected Coal-Fired Generating Capacity 3/

	SWPP		MAIN		MARCA-WSCC	
	MW	Ave. ann. growth rate	MW	Ave. ann. growth rate	MW	Ave. ann. growth rate
1980	17,727		30,511		38,487	
1985	23,928	6.2	28,604		49,007	4.9
2000	28,298	1.1	39,251		80,270	3.3
Overall avg.ann. growth rate		2.4		1.3		3.8

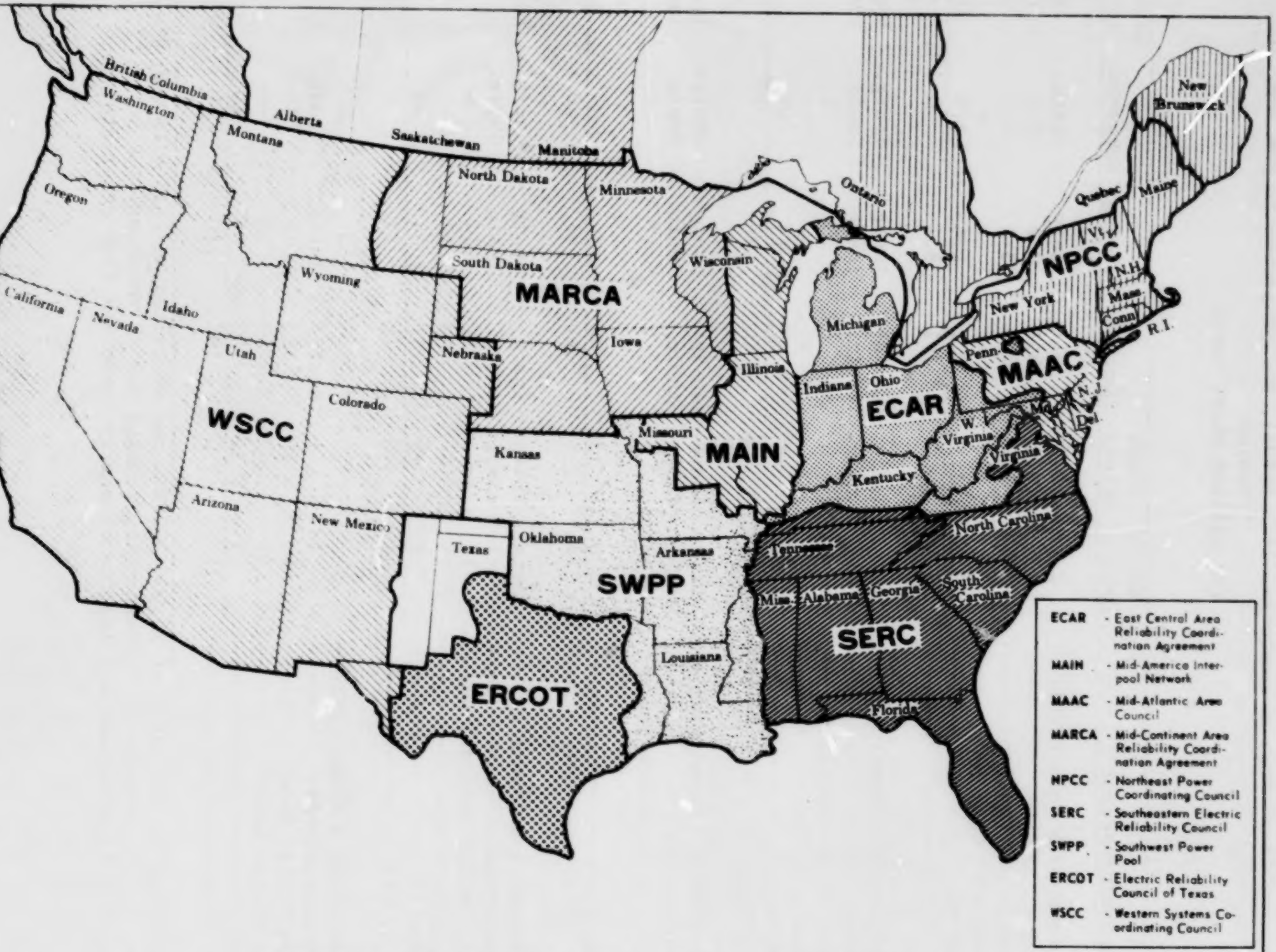
Contracts for shipments to these areas in the year 1980 were totalled and assumptions were made for the SWPP and MARCA-WSCC areas that coal exports would grow to each of these regions at the same rate of growth in coal-fired capacity from 1980 to 1985, and from 1985 to 2000. For the MAIN area the overall growth rate from 1980 to 2000 was applied to exports to that area because of the decline in generating capacity in 1985 from the 1980 total of the region. Thus the following export figures were calculated:

NGP Coal Exports (in million tons)

	1980	1985	2000
Export Demand			
SWPP	21	29	34
MAIN	23	26	30
MARCA-WSCC	22	29	45
South Dakota-Nebraska	7	10	31
Total	73	94	140

To obtain the net export figures in tables 5 and 6 , the exports to South Dakota and Nebraska were considered as imports and subtracted from the total. The individual export figures by State were then calculated basically on a percentage basis for 1985 and 2000 using the 1980 proportions. In general, it can be assumed that in the future Wyoming will supply the SWPP area; Montana, the MAIN area; and the MARCA-WSCC area will be distributed between North Dakota, Montana, and Wyoming.

3/ Source: Base Case, Task Force Report on Fuel Use Alternatives to the Technical Advisory Comm. on Fuels, FPC, National Power Survey, Oct. 1973.


British Columbia
Alberta
Saskatchewan
Manitoba
Ontario
Quebec
New Brunswick
Washington
Oregon
California
Nevada
Idaho
Montana
Wyoming
Utah
Colorado
Arizona
New Mexico
North Dakota
South Dakota
Nebraska
Kansas
Oklahoma
Texas
Minnesota
Iowa
Missouri
Arkansas
Louisiana
Wisconsin
Illinois
Michigan
Indiana
Ohio
Kentucky
Tennessee
Miss.
Alabama
Georgia
Florida
South Carolina
North Carolina
Virginia
W. Virginia
Penn.
Md.
Del.
N.J.
New York
Vt.
N.H.
Maine
Mass.
Conn.
R.I.
WSCC
MARCA
MAIN
ECAR
NPCC
MAAC
SWPP
ERCOT
SERC
ECAR - East Central Area Reliability Coordination Agreement
MAIN - Mid-America Interpool Network
MAAC - Mid-Atlantic Area Council
MARCA - Mid-Continent Area Reliability Coordination Agreement
NPCC - Northeast Power Coordinating Council
SERC - Southeastern Electric Reliability Council
SWPP - Southwest Power Pool
ERCOT - Electric Reliability Council of Texas
WSCC - Western Systems Coordinating Council

REGIONAL ELECTRIC RELIABILITY COUNCILS

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INTERMEDIATE SCENARIO

Table 5. Northern Great Plains Region - Coal Supply Schedule - a mixed development program embodying large generating plants, coal conversion plants, and exports, 1971 actual, and projected to the year 2000

Demand

(in million short tons)

Year	Consuming Sector	North Dakota	South Dakota	Montana	Wyoming	Nebraska	Regional Total
1971	Household & Commercial---	0.1	0.1	0.1	insig.	insig.	0.3
	Industrial---------------	0.2	0.2	0.1	0.2	0.1	0.8
	Electrical Generation----	3.5	1.2	0.8	3.5	0.9	9.9
	Synthetic Gas------------	-	-	-	-	-	-
	Exports------------------	2.3	-1.5	6.1	4.4	-1.0	10.3
	Total-----------------	6.1	0	7.1	8.1	0	21.3
1975	Household & Commercial---	insig.	insig.	insig.	insig.	insig.	insig.
	Industrial---------------	insig.	insig.	insig.	insig.	insig.	insig.
	Electrical Generation----	5	2	2	8	1	18
	Synthetic Gas------------	-	-	-	-	-	-
	Exports------------------	4	-2	18	15	-1	34
	Total-----------------	9	0	20	23	0	52
1980	Household & Commercial---	insig.	insig.	insig.	insig.	insig.	insig.
	Industrial---------------	insig.	insig.	insig.	insig.	insig.	insig.
	Electrical Generation----	13	3	9	12	4	41
	Synthetic Gas------------	-	-	-	-	-	-
	Exports------------------	6	-3	32	35	-4	66
	Total-----------------	19	0	41	47	0	107
1985	Household & Commercial---	insig.	insig.	insig.	insig.	insig.	insig.
	Industrial---------------	1	insig.	insig.	insig.	insig.	1
	Electrical Generation----	19	5	11	14	5	54
	Synthetic Gas------------	15	-	23	15	-	53
	Exports------------------	9	-5	41	44	-5	84
	Total-----------------	44	0	75	73	0	192
2000	Household & Commercial---	-	-	-	-	-	0
	Industrial---------------	1	1	insig.	insig.	insig.	2
	Electrical Generation----	50	20	28	22	10	130
	Synthetic Gas------------	53	-	45	23	-	121
	Exports------------------	15	-21	60	65	-10	109
	Total-----------------	119	0	133	110	0	362

NOTE: Converted on the basis of 15,000,000 Btu per short ton of coal although Btu's may not convert exactly to corresponding tonnage due to rounding.
Negative figures indicate imports of energy resources from other States.

INTERMEDIATE SCENARIO

Table 6. Northern Great Plains Region - Coal Supply Schedule - a mixed development program embodying large generating plants, coal conversion plants, and exports, 1971 actual, and projected to the year 2000

Demand

(in trillion Btu)

Year	Consuming Sector	North Dakota	South Dakota	Montana	Wyoming	Nebraska	Regional Total
1971	Household & Commercial---	2.8	1.2	3.7	0.7	0.6	9.0
	Industrial---------------	6.5	5.1	1.1	4.5	4.4	21.6
	Electric Generation------	78.4	26.1	17.4	78.4	19.8	220.1
	Synthetic Gas------------	-	-	-	-	-	-
	Exports------------------	63.4	-32.4	153.6	116.7	-24.8	276.5
	Total------------------	151.1	0	175.8	200.3	0	527.2
1975	Household & Commercial---	2	1	3	insig.	insig.	6
	Industrial---------------	7	5	1	5	5	23
	Electric Generation------	75	30	30	120	15	270
	Synthetic Gas------------	-	-	-	-	-	-
	Exports------------------	60	-36	270	225	-20	499
	Total------------------	144	0	304	350	0	798
1980	Household & Commercial---	1	1	2	insig.	insig.	4
	Industrial---------------	7	6	1	5	5	24
	Electric Generation------	195	45	135	180	60	615
	Synthetic Gas------------	-	-	-	-	-	-
	Exports------------------	90	-52	480	525	-65	978
	Total------------------	293	0	618	710	0	1,621
1985	Household & Commercial---	insig.	insig.	1	insig.	insig.	1
	Industrial---------------	8	6	1	5	5	25
	Electric Generation------	285	75	165	210	75	810
	Synthetic Gas------------	228	-	340	228	-	796
	Exports------------------	135	-81	615	660	-80	1,249
	Total------------------	656	0	1,122	1,103	0	2,881
2000	Household & Commercial---	-	-	-	-	-	0
	Industrial---------------	10	8	2	7	6	33
	Electric Generation------	750	300	420	330	150	1,950
	Synthetic Gas------------	796	-	681	340	-	1,817
	Exports------------------	225	-308	900	975	-156	1,636
	Total------------------	1,781	0	2,003	1,652	0	5,436

NOTE: Converted on the basis of 15,000,000 Btu per short ton of coal although Btu's may not convert exactly to corresponding tonnage due to rounding.

THE LOW COAL DEVELOPMENT FORECAST

In developing the Low Coal Development Forecast for the Northern Great Plains Region it was assumed that there would be no development of coal resources other than those necessary to meet regional demand, previously committed demand and near-term foreseeable demand. Coal supply from the NGPR under the Low Forecast is illustrated in tables 7 and 8 . The following tabulation shows the difference in coal production (supply) between the Low Coal Development Forecast and the Intermediate Forecast:

	NGP Coal Production (million tons)				
	1971	1975	1980	1985	2000
Low Forecast	21.3	52	91	108	144
Intermediate Forecast	21.3	52	107	192	362
Difference (million tons)	0	0	16	84	218

As shown, by the year 2000 there would be 218 million tons per year less production under the limited development scenario.

This low coal development forecast was derived with the following considerations and assumptions:

(a) Demand for the Household and Commercial, Industrial, and Transportation Sectors of the region were assumed to remain the same as the counterparts in the intermediate forecast for coal demand through the year 2000.

(b) It was assumed that under the low forecast there would be no synthetic gas industry in the NGPR. Thus, demand for coal would be lessened within the region under this assumption by the following amounts:

Coal Requirements for the Synthetic Gas Industry
(million tons)

	Intermediate		Low		Difference	
	1985	2000	1985	2000	1985	2000
North Dakota	15	53	0	0	15	53
Montana	23	45	0	0	23	45
Wyoming	15	23	0	0	15	23
Total	53	121	0	0	53	121

(c) In determining coal requirements for electrical generation within the NGPR a two-pronged approach was used. It was assumed that the Intermediate Forecast for the Electrical Generation Sector of the region, in particular net generation and coal requirements, would remain the same for the Low Forecast through the year 1985, for previously committed demand for electrical generation within the region would be unlikely to change by 1985. Thus, the difference in coal requirements for electrical generation under the Low Forecast for coal demand will differ from the Intermediate Forecast in the Year 2000 only. The results are as follows:

NGP Coal Requirements for Electrical
Generation for the Year 2000
(million tons)

	Intermediate Forecast	Low Forecast	Difference
North Dakota	50	24	26
South Dakota	20	9	11
Montana	28	28	0
Wyoming	22	22	0
Nebraska	10	5	5
Total	130	88	42

In deriving these requirements, exports of electrical energy from the individual States were assumed to remain constant with the 1985 level of exports for the year 2000. Thus, demand for electrical energy for the Low Forecast in 2000 would equal the sum of the 1985 export level of electricity in the region and the regional demand for electric energy in the year 2000, as expressed in the Intermediate Forecast. This demand was then translated into additional requirements for coal-fired capacity over the 1985 levels to derive the demand for coal inputs for the year 2000. As shown, a total of 42 million tons less production is realized in the year 2000 by limiting exports of electrical energy to the 1985 level and satisfying only regional demand.

(d) In determining coal inputs to the export sector of the Low Forecast it was assumed that exports would remain at the same level as the Intermediate Forecast for the Year 1975. After that year near-term potential and existing contracts for out-of-State estimates of coal exports in the years 1980 and 1985 were assumed to determine the export level in 1985. (See Intermediate Coal Supply Forecast) After 1985 coal exports were assumed to remain at the same level. A summary comparison of the export sector for coal demand is as follows:

NGP Coal Requirements for out-of-State Shipments
(million tons) (negative figures indicate imports)

	Intermediate			Low			Difference		
	1980	1985	2000	1980	1985	2000	1980	1985	2000
North Dakota	6	9	15	6	6	8	0	3	7
South Dakota	-3	-5	-21	-3	-5	-10	0	0	-11
Montana	32	41	60	26	28	30	6	13	30
Wyoming	35	44	65	25	29	31	10	15	34
Nebraska	-4	-5	-10	-4	-5	-5	0	0	-5
Total	66	84	109	50	53	54	16	31	55

Thus, by the year 2000 demand would decrease by 55 million tons with the limitation of exports under the Low Forecast.

Table 7 -Northern Great Plains Region - Low Coal Development Forecast Coal SupplySchedule 1971 Actual, and Projected to the Year 2000.

No development of coal resources other than those necessary to meet regional demand, and previously committed demand.

Demand
(in million short tons)

Year	Consuming Sector	North Dakota	South Dakota	Montana	Wyoming	Nebraska	Regional Total
1971	Household and Commercial	0.1	0.1	0.1	insig.	insig.	0.3
	Industrial	0.2	0.2	0.1	0.2	0.1	0.8
	Electrical Generation	3.5	1.2	0.8	3.5	0.9	9.9
	Synthetic gas	-	-	-	-	-	-
	Exports	2.3	-1.5	0.1	4.4	-1.0	10.3
	Total	6.1	0	7.1	8.1	0	21.3
1975	Household and Commercial	insig.	insig.	insig.	insig.	insig.	insig.
	Industrial	insig.	insig.	insig.	insig.	insig.	insig.
	Electrical Generation	5	2	2	8	1	18
	Synthetic gas	-	-	-	-	-	0
	Exports	4	-2	18	15	-1	34
	Total	9	0	20	23	0	52
1980	Household and Commercial	insig.	insig.	insig.	insig.	insig.	insig.
	Industrial	insig.	insig.	insig.	insig.	insig.	insig.
	Electrical Generation	13	3	9	12	4	41
	Synthetic gas	-	-	-	-	-	0
	Exports	6	-3	26	25	-4	50
	Total	19	0	35	37	0	91
1985	Household and Commercial	insig.	insig.	insig.	insig.	insig.	insig.
	Industrial	1	insig.	insig.	insig.	insig.	1
	Electrical Generation	19	5	11	14	5	54
	Synthetic gas	-	-	-	-	-	0
	Exports	6	-5	28	29	-5	53
	Total	26	0	39	43	0	108
2000	Household and Commercial	-	-	-	-	-	-
	Industrial	1	1	insig.	insig.	insig.	2
	Electrical generation	24	9	28	22	5	88
	Synthetic gas	-	-	-	-	-	0
	Exports	8	-10	30	31	-5	54
	Total	33	0	58	55	0	144

Table 8 . - Northern Great Plains Region - Low Coal Development Forecast
Coal Supply Schedule 1971 Actual, and Projected to the Year 2000

No development of coal resources other than those necessary to meet regional demand, and previously committed demand.

		Demand (in trillion Btu)					
Year	Consuming Sector	North Dakota	South Dakota	Montana	Wyoming	Nebraska	Regional Total
1971	Household and Commercial-------	2.8	1.2	3.7	0.7	0.6	9.0
	Industrial---------	6.5	5.1	1.1	4.5	4.4	21.6
	Electrical Generation--------	78.4	26.1	17.4	78.4	19.8	220.1
	Synthetic gas------	-	-	-	-	-	-
	Exports------------	6.4	-32.4	153.6	116.7	-24.8	276.5
	Total-------	151.1	0	175.8	200.3	0	527.2
1975	Household and Commercial-----	2	1	3	insig.	insig.	6
	Industrial-------	7	5	1	5	5	23
	Electrical Generation-----	75	30	30	120	15	270
	Synthetic gas----	-	-	-	-	-	-
	Exports----------	60	-36	270	225	-20	499
	Total-----	144	0	304	350	0	798
1980	Household and Commercial-----	1	1	2	insig.	insig.	4
	Industrial-------	7	6	1	5	5	24
	Electrical Generation-----	195	45	135	180	60	615
	Synthetic gas----	-	-	-	-	-	0
	Exports----------	90	-52	390	375	-65	0
	Total-----	293	0	528	560	0	643
1985	Household and Commercial-----	insig.	insig.	1	insig.	insig.	1
	Industrial-------	8	6	1	5	5	25
	Electrical Generation-----	285	75	165	210	75	810
	Synthetic gas----	-	-	-	-	-	-
	Exports----------	90	-81	420	435	-80	784
	Total-----	383	0	587	650	0	1,620
2000	Household and Commercial-----	-	-	-	-	-	-
	Industrial-------	10	8	2	7	6	33
	Electrical generation-----	360	135	420	330	75	1,320
	Synthetic gas----	-	-	-	-	-	-
	Exports----------	120	-143	450	465	-81	811
	Total-----	490	0	872	832	0	2,164

THE HIGH COAL DEVELOPMENT FORECAST

The following tabulation shows the projected demand for NGP coal under the High Coal Development Scenario as compared to the demand under the Intermediate Forecast:

	NGP Coal Production (million tons)				
	1971	1975	1980	1985	2000
High Development Forecast	21.3	52	160	382	977
Intermediate Forecast	21.3	52	107	192	362
Difference	0	0	53	190	615

As shown, by 1985 there would be 190 million tons more production under the High Development Forecast than under the Intermediate Forecast. By 2000, NGP coal production would reach 977 million tons per year, 615 million tons greater than under the projected production for the Intermediate Forecast. Coal demand from the NGPR is illustrated by sector in detail in tables 9 and 10.

The High Development Forecast for NGP coal was derived under the following considerations and assumptions and their subsequent impacts:

(a) It was assumed that the Nation would receive the lowest possible imports of natural gas from Canada as estimated by the Canadian government. 1/ This is depicted in the following tabulation:

U.S. Natural Gas Imports from Canada (in billion cu.ft.)

	Canadian Estimates		
	High	Low	Difference
1980	2,000	1,000	1,000
1985	3,000	900	2,100
2000	4,000	0	4,000

1/ "An Energy Policy for Canada," Canadian Minister of Energy, Mines, and Resources.

It was further assumed that the differences in imports of natural gas must be made up through coal conversion to synthetic gas and that one-half of this conversion would take place in the NGPR. In addition, the region would still produce the same amount of synthetic gas as projected in the Intermediate Forecast. Therefore the NGPR must produce at least the following amount of gas in the future:

Production of Synthetic Gas (bil. cu.ft.)

	Intermediate	One-half of Deficit in imports	Total
1980 ------	0	500	500
1985 ------	578	1,050	1,628
2000 ------	1,321	2,000	3,321

Assuming the utilization of synthetic gas plants with a 250 million cubic feet per day of production capacity, it is projected that the plants required will be distributed:

Number of 250 MMcf/day Synthetic Gas Plant Operations Under the High Development Scenario

State	1980	1985	2000
North Dakota------	3	6	17
Montana-----------	3	8	15
Wyoming ----------	1	6	9
Total ---------	7	20	41

The corresponding production of synthetic gas is subsequently forecast:

Production of Synthetic Gas Under the High Development Scenario

	1980 billion cu.ft.	1985 billion cu.ft.	2000 billion cu.ft.
North Dakota --------	248	495	1,403
Montana ------------	248	660	1,237
Wyoming--------------	82	495	742
Total------	578	1,650	3,382

Coal requirements necessary to achieve this level of synthetic gas production along with comparisons to the Intermediate Forecast are illustrated in the following table 2/:

Demand for NGP Coal for NGP Synthetic Gas Production (in million tons)

	1980			1985			2000		
	Intermediate	High	Difference	Intermediate	High	Difference	Intermediate	High	Difference
North Dakota	0	23	23	15	46	31	53	129	76
Montana	0	23	23	23	61	38	45	114	69
Wyoming	0	7	0	15	46	31	23	68	45
Total	0	53	46	53	153	100	120	311	191

Thus, by the year 2000, 311 million tons of NGP coal would be required for synthetic gas production under the High Development Forecast.

In determining NGP coal requirements for the High Coal Development Forecast, it was further assumed that there would be a lag in national nuclear generating capacity reaching 20,000 MW by 1985 and 20 percent by 2000 (equal to 240,000 MW). This lag in nuclear capacity was assumed to be alleviated by the construction of coal-fired generating capacities. To determine the effect upon demand for NGP coal the following methodology was used.

Regional Electric Reliability Council (see map) projections for nuclear generating capacity were used for the relevant years. The 1985 total nuclear capacity was cut by 20,000 MW and distributed to reliability areas on a percentage basis. For the year 2000 each regional projection for nuclear capacity was cut by 20 percent. This is illustrated in the following table:

2/ Assuming 65 percent conversion efficiency and 15,000,000 Btu/short ton. This translates into 7.6 million ton/year requirement for each plant at full operation.

Projected Nuclear Generating Capacity by Regional Electric Reliability Councils 1985, 2000

	1985			2000	
Council (see map)	Projected nuclear capacity	% of Total	Nuclear capacity reductor=increase in coal-fired capacity	Projected nuclear capacity	20% reductions in nuclear=increase in coal-fired capacity
NPPC	29,960	10.7	2,140	108,000	21,600
MAAC	33,880	12.1	2,420	109,200	21,840
SERC	90,160	32.2	6,440	370,800	74,160
ECAR	24,640	8.8	1,760	99,600	19,920
MAIN	27,160	9.7	1,940	94,800	18,960
SWPP	25,760	9.2	1,840	164,400	32,880
ERCOT	12,320	4.4	880	98,400	19,680
MARCA	5,600	2.0	400	31,200	6,240
WSCC	30,520	10.9	2,180	123,600	24,720
	254,240	100.0	20,000	1,200,000	240,000

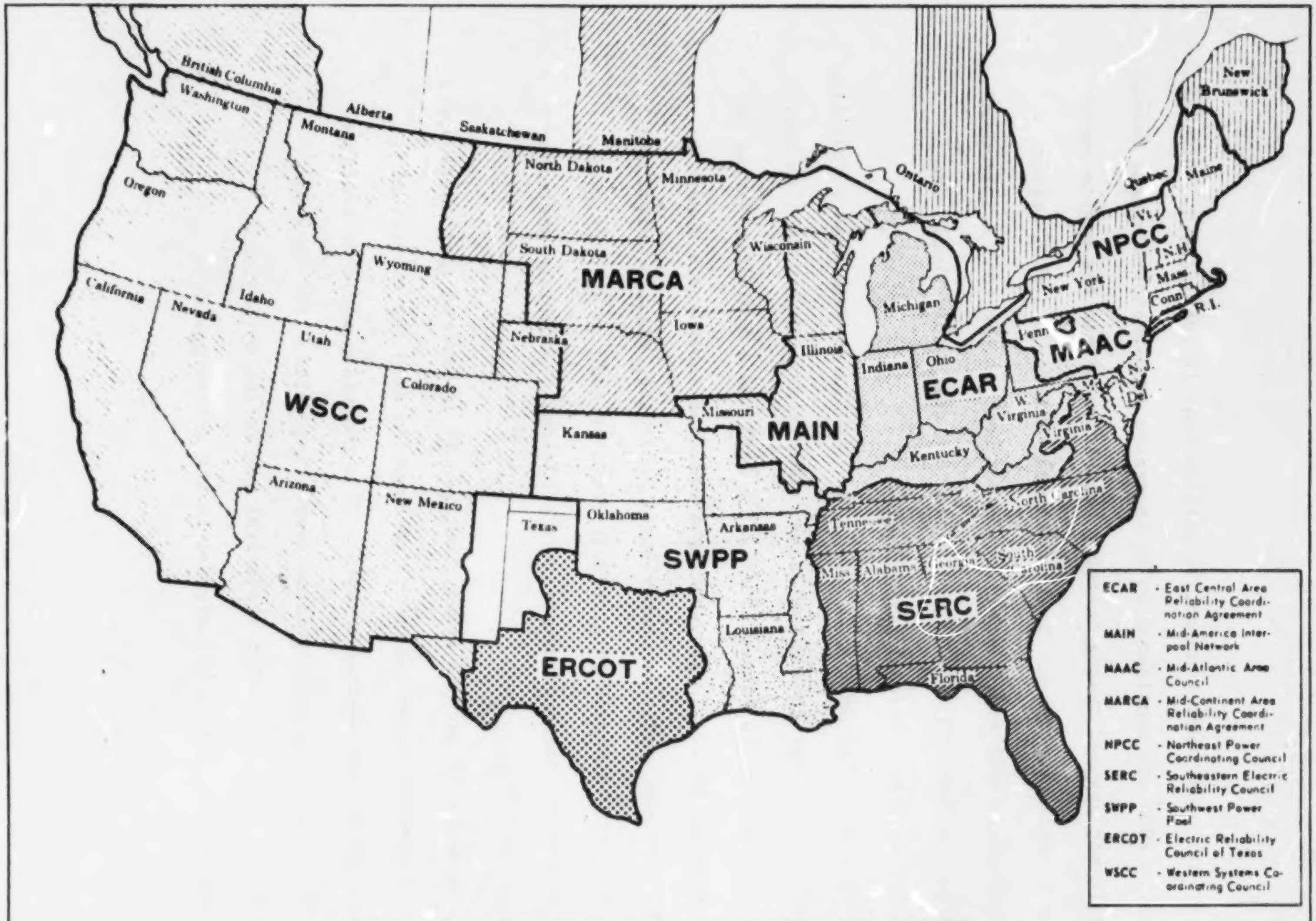
The NGPR could be logically expected to supply the following regions at the most. (Also listed are the required generating capacities and coal requirements) 3/.

	Demand (in million tons)			
	1985		2000	
Market area	MW	Coal requirements (million tons)	MW	Coal requirements (million tons)
1/2 MAIN	970	4	9,480	39
SWPP	1,840	7	32,880	137
ERCOT	880	4	19,680	82
MARCA	400	2	6,240	26
1/2 WSCC	1,090	4	12,360	51
Total	5,180	21	80,640	335

This production is projected to be distributed in the following way:

Coal Production (in million tons)	1985	2000
North Dakota	1	3
Montana	9	150
Wyoming	11	182
Total	21	335

3/ Based on 15,000,000 Btu/short ton, 1,000 MW require 4.15 million tons per year


British Columbia
Alberta
Saskatchewan
Manitoba
Ontario
Quebec
New Brunswick
Washington
Oregon
California
Nevada
Idaho
Montana
Wyoming
Utah
Arizona
Colorado
New Mexico
North Dakota
South Dakota
Nebraska
Kansas
Oklahoma
Texas
Minnesota
Iowa
Missouri
Arkansas
Louisiana
Wisconsin
Illinois
Michigan
Indiana
Ohio
Kentucky
Tennessee
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Florida
South Carolina
North Carolina
Virginia
W. Virginia
Penn
New York
N.J.
Del.
Vt.
N.H.
Maine
Mass
Conn
R.I.
WSCC
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ECAR - East Central Area Reliability Coordination Agreement
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SERC - Southeastern Electric Reliability Council
SWPP - Southwest Power Pool
ERCOT - Electric Reliability Council of Texas
WSCC - Western Systems Coordinating Council

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This additional tonnage, 21 million tons in 1985, and 335 million tons in 2000 are considered to be increases in NGP export sector demand for it was assumed that generating capacities within the region would remain constant. It was further assumed that for the WSCC region, southwestern coal would supply the other half of the coal requirements and that within the MAIN region midwestern coal would supply the balance of the additional requirements.

The High Coal Development Forecast finally assumed that a reduction in oil imports for the United States would result in a 3 million barrel per day national petroleum shortage in 1985 and a 5 million barrel per day shortage by 2000. The shortages would be known early enough to enable the employment of technologies, policies, etc., to eliminate the deficit. Although this deficit could be made up in many ways, the following course of events were projected to occur to maximize demand for NGP coal.

In event of the projected shortages it is assumed that there would be a 50 percent reduction in oil consumption used for electrical generation in the benchmark years. This reduction would be replaced by the utilization of coal-fired generating units. FPC data on future oil consumption for electrical generation by regional reliability council is illustrated in the following table:

Oil Requirements for Electrical Generation
(in million barrels)

	1985		2000	
	Demand	50% Reduction	Demand	50% Reduction
NPPC	348	174	294	147
MAAC	122	61	141	71
SERC	291	146	338	169
ECAR	87	44	303	152
ERCOT	74	37	120	60
MARCA	77	38	110	55
MAIN	104	52	135	68
SWPP	78	39	56	28
WSCC	160	80	231	116
	1,341	671	1,728	866
Barrels/day	3.7	1.8	4.7	2.4

The NGPR is expected to supply the following regions with coal for electric generation to offset the reductions in oil-fired capacities: ERCOT, MARCA, one-half of MAIN, SWPP, one-half of WSCC. Coal requirements are as follows: 4/

Coal requirements (million tons)

	1985	2000
Montana	31	41
Wyoming	38	49
	69	90

This additional 69 million tons in 1985, and 90 million tons in 2000 are considered to be demands from the NGP export sectors for the sake of clarity.

Total national savings from a 50 percent cutback in oil-fired electrical generation would total 1.8 million barrels per day in 1985 and 2.4 million barrels per day by 2000. The balance of the deficit (3MMbbl/d in 1985, 5 MMbbl/d in 2000) will be made up through other fuel shifts, employment of energy conservation policies and possible development of the oil shale industry. It is unlikely that coal liquefaction, even under this scenario, would be competitive with other fuel sources.

4/ Coal requirements calculated on a Btu for Btu basis with the replaced oil requirements.

The significance of NGP coal to the national energy requirements is illustrated in the following table:

	High Development Forecast			
	NGP Coal Production		National Energy Requirements 1/	NGP Coal as % of National Requirements
	(Million Tons)	(Trillion Btu)	(trillion Btu)	
1971	21.3	527.2	68,989	0.8
1975	52	798	80,265	1.0
1980	160	2,416	96,020	2.5
1985	382	5,730	116,630	4.9
2000	977	14,659	191,900	7.6

1/ From U.S. Energy Through the Year 2000, U.S. Dept. of Interior, Dec. 1972.

As shown, NGP coal will become very important to the Nation's energy requirements under the High Development Forecast than under the Intermediate Forecast, reaching 7.6 percent of the Nation's energy requirements by the year 2000.

Tables 9 and 10 illustrate detailed demand for coal under the High Coal Development Scenario.

Table 9 ..--Northern Great Plains Region - High Coal Development Forecast - Coal Supply Schedule 1971 Actual, and Projected to the Year 2000

Extensive development of coal resources to aid in alleviating assumed national energy supply shortages

Demand
(in million short tons)

Year	Consuming Sector	North Dakota	South Dakota	Montana	Wyoming	Nebraska	Regional Total
1971	Household and Commercial	0.1	0.1	0.1	insig.	insig.	0.3
	Industrial	0.2	0.2	0.1	0.2	0.1	0.8
	Electrical Generation	3.5	1.2	0.8	3.5	0.9	9.9
	Synthetic gas	-	-	-	-	-	-
	Exports	2.3	-1.5	0.1	4.4	-1.0	10.3
	Total	6.1	0	7.1	8.1	0	21.3
1975	Household and Commercial	insig.	insig.	insig.	insig.	insig.	insig.
	Industrial	insig.	insig.	insig.	insig.	insig.	insig.
	Electrical Generation	5	2	2	8	1	18
	Synthetic gas	-	-	-	-	-	0
	Exports	4	-2	18	15	-1	34
	Total	9	0	20	23	0	52
1980	Household and Commercial	insig.	insig.	insig.	insig.	insig.	insig.
	Industrial	insig.	insig.	insig.	insig.	insig.	insig.
	Electrical Generation	13	3	9	12	4	41
	Synthetic gas	23	-	23	7	-	53
	Exports	6	-3	32	35	-4	66
	Total	42	0	64	54	0	160
1985	Household and Commercial	insig.	insig.	insig.	insig.	insig.	insig.
	Industrial	1	insig.	insig.	insig.	insig.	1
	Electrical Generation	19	5	11	14	5	54
	Synthetic gas	46	-	61	46	-	153
	Exports	10	-5	81	93	-5	174
	Total	76	0	153	153	0	382
2000	Household and Commercial	-	-	-	-	-	-
	Industrial	1	1	insig.	insig.	insig.	2
	Electrical Generation	50	20	28	22	10	130
	Synthetic gas	129	-	114	68	-	311
	Exports	18	-21	251	296	-10	534
	Total	198	0	393	386	0	977

Table 10.--Northern Great Plains Region - High Coal Development Forecast - Coal Supply Schedule 1971 Actual, and Projected to the Year 2000

Extensive development of coal resources to aid in alleviating assumed national energy supply shortages

Demand

(in trillion Btu)

Year	Consuming Sector	North Dakota	South Dakota	Montana	Wyoming	Nebraska	Regional Total
1971	Household and Commercial--------	2.8	1.2	3.7	0.7	0.6	9.0
	Industrial---------	6.5	5.1	1.1	4.5	4.4	21.6
	Electrical Generation--------	78.4	26.1	17.4	78.4	19.8	220.1
	Synthetic gas------	-	-	-	-	-	-
	Exports------------	6.4	-32.4	153.6	116.7	-24.8	276.5
	Total---------	151.1	0	175.8	200.3	0	527.2
1975	Household and Commercial--------	2	1	3	insig.	insig.	6
	Industrial---------	7	5	1	5	5	23
	Electrical Generation--------	75	30	30	120	15	270
	Synthetic gas------	-	-	-	-	-	-
	Exports------------	60	-36	270	225	-20	499
	Total---------	144	0	304	350	0	798
1980	Household and Commercial--------	1	1	2	insig.	insig.	4
	Industrial---------	7	6	1	5	5	24
	Electrical Generation--------	195	45	135	180	60	615
	Synthetic gas------	345	-	345	105	-	795
	Exports------------	90	-52	480	525	-65	978
	Total---------	638	0	963	815	0	2,416
1985	Household and Commercial--------	insig.	insig.	1	insig.	insig.	1
	Industrial---------	8	6	1	5	5	25
	Electrical Generation--------	285	75	165	210	75	810
	Synthetic gas------	690	-	915	690	-	2,295
	Exports------------	150	-81	1,215	1,395	-80	2,599
	Total---------	1,133	0	2,297	2,300	0	5,730
2000	Household and Commercial--------	-	-	-	-	-	0
	Industrial---------	10	8	2	7	6	33
	Electrical Generation--------	750	300	420	330	150	1,950
	Synthetic gas------	1,935	-	1,710	1,020	-	4,665
	Exports------------	270	-308	3,765	4,440	-156	8,011
	Total----------	2,965	0	5,897	5,797	0	14,659

APPENDIX II-A.

NORTHERN GREAT PLAINS REGION

ENERGY CONSUMPTION FORECAST THROUGH THE YEAR 2000

FORECAST TABLES

App. II-A Table 1 --Northern Great Plains Region Consumption of Energy Resources by Major Sources and Consuming Sectors, 1971 actual, and projected to the year 2000 (in trillion Btu's)

	Coal	Petroleum	Natural Gas	Total Fossil Fuels	Hydro-power	Nuclear	Total Gross Inputs	Utility Electricity Distributed	Net Inputs
1971									
Household & Commercial--	9.0	145.0	213.0	367.0	--	--	367.0	63.5	430.5
Industrial--------------	21.6	47.9	207.7	277.2	--	--	277.2	39.1	316.3
Transportation----------	--	399.1	22.9	422.0	--	--	422.0	0.3	422.3
Electrical Generation---	220.1	4.7	58.4	283.2	237.6	--	520.8	(102.9)	--
Miscellaneous-----------	--	96.8	--	96.8	--	--	96.8	--	96.8
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total-----------------	250.7	693.5	502.0	1,446.2	237.6	--	1,683.8	--	1,265.9
1975									
Household & Commercial--	6	152	237	395	--	--	395	80	475
Industrial--------------	23	57	221	301	--	--	301	55	356
Transportation----------	--	430	25	455	--	--	455	insig.	455
Electrical Generation---	270	8	52	330	228	75	633	(135)	--
Miscellaneous-----------	--	98	--	98	--	--	98	--	98
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total-----------------	299	745	535	1,579	228	75	1,882	--	1,384
1980									
Household & Commercial--	4	167	262	433	--	--	433	118	551
Industrial--------------	24	68	248	340	--	--	340	79	419
Transportation----------	--	477	28	505	--	--	505	insig.	505
Electrical Generation---	615	24	52	691	219	75	985	(197)	--
Miscellaneous-----------	--	98	--	98	--	--	98	--	98
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total-----------------	643	834	590	2,067	219	75	2,361	--	1,573
1985									
Household & Commercial--	1	182	280	463	--	--	463	162	625
Industrial--------------	25	82	270	377	--	--	377	104	481
Transportation----------	--	520	33	553	--	--	533	insig.	553
Electrical Generation---	810	42	52	904	214	151	1,269	(266)	--
Miscellaneous-----------	--	98	--	98	--	--	98	--	98
Synthetic Gas-----------	796	--	--	796	--	--	796	--	--
Total-----------------	1,632	924	635	3,191	214	151	3,556	--	1,757
2000									
Household & Commercial--	--	229	346	575	--	--	575	286	861
Industrial--------------	33	122	349	504	--	--	504	183	687
Transportation----------	--	652	43	695	--	--	695	insig.	695
Electrical Generation---	1,950	126	52	2,128	197	360	2,685	(469)	--
Miscellaneous-----------	--	98	--	98	--	--	98	--	98
Synthetic Gas-----------	1,817	--	--	1,817	--	--	1,817	--	--
Total-----------------	3,800	1,227	790	5,817	197	360	6,374	--	2.341

App. II-A.

Table 2.--North Dakota Consumption of Energy Resources by Major Sources and Consuming Sectors, 1971 actual, and projected to the year 2000
(in trillion Btu's)

	Coal	Petroleum	Natural Gas	Total Fossil Fuels	Hydro-power	Nuclear	Total Gross Inputs	Utility Electricity Distributed	Net Inputs
1971									
Household & Commercial	2.8	30.5	18.1	51.4	--	--	51.4	9.3	60.7
Industrial	6.5	6.2	16.7	29.4	--	--	29.4	1.6	31.0
Transportation	--	61.2	--	61.2	--	--	61.2	--	61.2
Electrical Generation	78.4	1.3	0.4	80.1	33.2	--	113.3	(10.9)	--
Miscellaneous	--	6.7	--	6.7	--	--	6.7	--	6.7
Synthetic Gas	--	--	--	--	--	--	--	--	--
Total	87.7	105.9	35.2	228.8	33.2	--	262.0	--	159.6
1975									
Household & Commercial	2	32	20	54	--	--	54	13	67
Industrial	7	7	17	31	--	--	31	3	34
Transportation	--	67	--	67	--	--	67	--	67
Electrical Generation	75	1	insig.	76	31	--	107	(16)	--
Miscellaneous	--	7	--	7	--	--	7	--	7
Synthetic Gas	--	--	--	--	--	--	--	--	--
Total	84	114	37	235	31	--	266	--	175
1980									
Household & Commercial	1	34	23	58	--	--	58	19	77
Industrial	7	8	20	35	--	--	35	5	40
Transportation	--	72	--	72	--	--	72	--	72
Electrical Generation	195	6	insig.	201	29	--	230	(24)	--
Miscellaneous	--	7	--	7	--	--	7	--	7
Synthetic Gas	--	--	--	--	--	--	--	--	--
Total	203	127	43	373	29	--	402	--	196
1985									
Household & Commercial	insig.	36	25	61	--	--	61	26	87
Industrial	8	9	23	40	--	--	40	6	46
Transportation	--	77	--	77	--	--	77	--	77
Electrical Generation	285	12	insig.	297	28	--	325	(32)	--
Miscellaneous	--	7	--	7	--	--	7	--	7
Synthetic Gas	228	--	--	228	--	--	228	--	--
Total	521	141	48	710	28	--	738	--	217
2000									
Household & Commercial	--	42	35	77	--	--	77	43	120
Industrial	10	11	30	51	--	--	51	12	63
Transportation	--	91	--	91	--	--	91	--	91
Electrical Generation	750	36	insig.	786	26	--	812	(55)	--
Miscellaneous	--	7	--	7	--	--	7	--	7
Synthetic Gas	796	--	--	796	--	--	796	--	--
Total	1,556	187	65	1,808	26	--	1,834	--	281

Table 3. South Dakota Consumption of Energy Resources by Major Sources and Consuming Sectors, 1971 actual, and projected to the year 2000
(in trillion Btu's)

	Coal	Petroleum	Natural Gas	Total Fossil Fuels	Hydro-power	Nuclear	Total Gross Inputs	Utility Electricity Distributed	Net Inputs
1971									
Household & Commercial--	1.2	30.7	21.9	53.8	--	--	53.8	9.5	63.3
Industrial--------------	5.1	3.2	7.5	15.8	--	--	15.8	1.5	17.3
Transportation----------	--	64.1	--	64.1	--	--	64.1	--	64.1
Electrical Generation---	26.1	1.4	3.4	30.9	79.3	--	110.2	(11.0)	--
Miscellaneous-----------	--	4.7	--	4.7	--	--	4.7	--	4.7
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total----------------	32.4	104.1	32.8	169.3	79.3	--	248.6	--	149.4
1975									
Household & Commercial--	1	31	25	57	--	--	57	12	69
Industrial--------------	5	3	8	16	--	--	16	2	18
Transportation----------	--	69	--	69	--	--	69	--	69
Electrical Generation---	30	1	3	34	75	--	109	(14)	--
Miscellaneous-----------	--	5	--	5	--	--	5	--	5
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total----------------	36	109	36	181	75	--	256	--	161
1980									
Household & Commercial--	1	32	27	60	--	--	60	18	78
Industrial--------------	6	2	8	16	--	--	16	3	19
Transportation----------	--	75	--	75	--	--	75	--	75
Electrical Generation---	45	6	3	54	70	--	124	(21)	--
Miscellaneous-----------	--	5	--	5	--	--	5	--	5
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total----------------	52	120	38	210	70	--	280	--	177
1985									
Household & Commercial--	insig.	34	30	64	--	--	64	23	87
Industrial--------------	6	2	8	16	--	--	16	3	19
Transportation----------	--	80	--	80	--	--	80	--	80
Electrical Generation---	75	6	3	84	67	--	151	(26)	--
Miscellaneous-----------	--	5	--	5	--	--	5	--	5
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total----------------	81	127	41	249	67	--	316	--	191
2000									
Household & Commercial--	--	38	36	74	--	--	74	40	114
Industrial--------------	8	2	10	20	--	--	20	5	25
Transportation----------	--	95	--	95	--	--	95	--	95
Electrical Generation---	300	30	3	333	62	--	395	(45)	--
Miscellaneous-----------	--	5	--	5	--	--	5	--	5
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total----------------	308	170	49	527	62	--	589	--	239

App. II-A. Table 4. Montana Consumption of Energy Resources by Major Sources and Consuming Sectors, 1971 actual, and projected to the year 2000
(in trillion Btu's)

	Coal	Petroleum	Natural Gas	Total Fossil Fuels	Hydro-power	Nuclear	Total Gross Inputs	Utility Electricity Distributed	Net Inputs
1971									
Household & Commercial--	3.7	22.4	42.3	68.4	--	--	68.4	11.2	79.6
Industrial--------------	1.1	13.1	50.5	64.7	--	--	64.7	23.1	87.8
Transportation----------	--	76.4	1.0	77.4	--	--	77.4	0.3	77.7
Electrical Generation---	17.4	--	1.1	18.5	98.3	--	116.8	(34.6)	--
Miscellaneous-----------	--	25.6	--	25.6	--	--	25.6	--	25.6
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total----------------	22.2	137.5	94.9	254.6	98.3	--	352.9	--	270.7
1975									
Household & Commercial--	3	24	47	74	--	--	74	13	87
Industrial--------------	1	18	56	75	--	--	75	31	106
Transportation----------	--	83	1	84	--	--	84	insig.	84
Electrical Generation---	30	--	1	31	97	--	128	(44)	--
Miscellaneous-----------	--	26	--	26	--	--	26	--	26
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total----------------	34	151	105	290	97	--	387	--	303
1980									
Household & Commercial--	2	26	50	78	--	--	78	21	99
Industrial--------------	1	25	63	89	--	--	89	41	130
Transportation----------	--	90	1	91	--	--	91	insig.	91
Electrical Generation---	135	--	1	136	97	--	233	(62)	--
Miscellaneous-----------	--	26	--	26	--	--	26	--	26
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total----------------	138	167	115	420	97	--	517	--	346
1985									
Household & Commercial--	1	28	52	81	--	--	81	28	109
Industrial--------------	1	33	71	105	--	--	105	51	156
Transportation----------	--	96	2	98	--	--	98	insig.	98
Electrical Generation---	165	insig.	1	166	96	--	262	(79)	--
Miscellaneous-----------	--	26	--	26	--	--	26	--	26
Synthetic Gas-----------	340	--	--	340	--	--	340	--	--
Total----------------	507	183	126	816	96	--	912	--	389
2000									
Household & Commercial--	--	35	58	93	--	--	93	52	145
Industrial--------------	2	55	87	144	--	--	144	90	234
Transportation----------	--	116	2	118	--	--	118	insig.	118
Electrical Generation---	420	6	1	427	88	--	515	(142)	--
Miscellaneous-----------	--	26	--	26	--	--	26	--	26
Synthetic Gas-----------	681	--	--	681	--	--	681	--	--
Total----------------	1,103	238	148	1,489	88	--	1,577	--	523

App. II-A.

Table 5. Wyoming Consumption of Energy Resources by Major Sources and Consuming Sectors, 1971 actual, and projected to the year 2000
(in trillion Btu's)

	Coal	Petroleum	Natural Gas	Total Fossil Fuels	Hydro-power	Nuclear	Total Gross Inputs	Utility Electricity Distributed	Net Inputs
1971									
Household & Commercial--	0.7	18.4	33.4	52.5	--	--	52.5	6.9	59.4
Industrial--------------	4.5	14.0	76.5	95.0	--	--	95.0	5.6	100.6
Transportation----------	--	59.1	8.2	67.3	--	--	67.3	--	67.3
Electrical Generation---	78.4	0.5	3.1	82.0	13.4	--	95.4	(12.5)	--
Miscellaneous-----------	--	50.1	--	50.1	--	--	50.1	--	50.1
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total---------------	83.6	142.1	121.2	346.9	13.4	--	360.3	--	227.3
1975									
Household & Commercial--	insig.	20	37	57	--	--	57	9	66
Industrial--------------	5	16	78	99	--	--	99	10	109
Transportation----------	--	63	9	72	--	--	72	--	72
Electrical Generation---	120	insig.	1	121	12	--	133	(19)	--
Miscellaneous-----------	--	50	--	50	--	--	50	--	50
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total---------------	125	149	125	399	12	--	411	--	297
1980									
Household & Commercial--	insig.	23	43	66	--	--	66	15	81
Industrial--------------	5	19	89	113	--	--	113	16	129
Transportation----------	--	73	10	83	--	--	83	--	83
Electrical Generation---	180	insig.	1	181	11	--	192	(31)	--
Miscellaneous-----------	--	50	--	50	--	--	50	--	50
Synthetic Gas-----------	--	--	--	--	--	--	--	--	--
Total---------------	185	165	143	493	11	--	504	--	343
1985									
Household & Commercial--	insig.	26	47	73	--	--	73	23	96
Industrial--------------	5	21	96	122	--	--	122	25	147
Transportation----------	--	82	12	94	--	--	94	--	94
Electrical Generation---	210	6	1	217	11	--	228	(48)	--
Miscellaneous-----------	--	50	--	50	--	--	50	--	50
Synthetic Gas-----------	228	--	--	228	--	--	228	--	--
Total---------------	443	185	156	784	11	--	795	--	387
2000									
Household & Commercial--	--	36	60	96	--	--	96	46	142
Industrial--------------	7	30	129	166	--	--	166	47	213
Transportation----------	--	109	18	127	--	--	127	--	127
Electrical Generation---	330	12	1	343	10	--	353	(93)	--
Miscellaneous-----------	--	50	--	50	--	--	50	--	50
Synthetic Gas-----------	340	--	--	340	--	--	340	--	--
Total---------------	677	237	208	1,122	10	--	1,132	--	532

p. II-A. Table 6.--Nebraska - Consumption of Energy Resources by Major Sources and Consuming Sectors, 1971 Actual and Projected to the Year 2000
(in trillion Btu's)

	Coal	Petroleum	Natural Gas	Total Fossil Fuels	Hydro-power	Nuclear	Total Gross Inputs	Utility Electricity Distributed	Net Inputs
1971									
Household & Commercial--	0.6	43.0	97.3	140.9	-	-	140.9	26.6	167.5
Industrial--------------	4.4	11.4	56.5	72.3	-	-	72.3	7.3	79.6
Transportation----------	-	138.3	13.7	152.0	-	-	152.0	-	152.0
Electrical Generation---	19.8	1.5	50.4	71.7	13.4	-	85.1	(33.9)	-
Miscellaneous-----------	-	9.7	-	9.7	-	-	9.7	-	9.7
Synthetic Gas-----------	-	-	-	-	-	-	-	-	-
Total----------------	24.8	203.9	217.9	446.6	13.4	-	460.0	-	408.8
1975									
Household & Commercial--	insig.	45	108	153	-	-	153	33	186
Industrial--------------	5	13	62	80	-	-	80	9	89
Transportation----------	-	148	15	163	-	-	163	-	163
Electrical Generation---	15	6	47	68	13	75	156	(42)	-
Miscellaneous-----------	-	10	-	10	-	-	10	-	10
Synthetic Gas-----------	-	-	-	-	-	-	-	-	-
Total----------------	20	222	232	474	13	75	562	-	448
1980									
Household & Commercial--	insig.	52	119	171	-	-	171	45	216
Industrial--------------	5	14	68	87	-	-	87	14	101
Transportation----------	-	167	17	184	-	-	184	-	184
Electrical Generation---	60	12	47	119	12	75	206	(59)	-
Miscellaneous-----------	-	10	-	10	-	-	10	-	10
Synthetic Gas-----------	-	-	-	-	-	-	-	-	-
Total----------------	65	255	251	571	12	75	658	-	511
1985									
Household & Commercial--	insig.	58	126	184	-	-	184	62	246
Industrial--------------	5	17	72	94	-	-	94	19	113
Transportation----------	-	185	19	204	-	-	204	-	204
Electrical Generation---	75	18	47	140	12	151	303	(81)	-
Miscellaneous-----------	-	10	-	10	-	-	10	-	10
Synthetic Gas-----------	-	-	-	-	-	-	-	-	-
Total----------------	80	288	264	632	12	151	795	-	573
2000									
Household & Commercial--	-	78	157	235	-	-	235	105	340
Industrial--------------	6	24	93	123	-	-	123	29	152
Transportation----------	-	241	23	264	-	-	264	-	264
Electrical Generation---	150	42	47	239	11	360	610	(134)	-
Miscellaneous-----------	-	10	-	10	-	-	10	-	10
Synthetic Gas-----------	-	-	-	-	-	-	-	-	-
Total----------------	156	395	320	871	11	360	1.242	-	766

App. II-A. Table 7.--Northern Great Plains Region-Consumption of Energy Resources by Major Sources and Consuming Sectors, 1971 actual, and projected to the year 2000
(in physical units)

	Coal (million tons)	Petroleum (million barrels)	Natural Gas (billion cu.ft.)	Hydropower (million kw-hr.)	Nuclear (million kw-hr.)	Electricity Distributed (million kw-hr.)
1971						
Household & Commercial--	0.3	27.3	206.7	---	---	18,615
Industrial--------------	0.8	8.3	201.7	---	---	11,456
Transportation----------	---	76.2	22.0	---	---	88
Electrical Generation---	9.9	0.7	56.7	23,243	---	---
Miscellaneous-----------	---	17.0	---	---	---	---
Synthetic Gas-----------	---	---	---	---	---	---
Total---------------	11.0	129.5	487.1	23,243	---	30,159
1975						
Household & Commercial--	insig.	29	230	---	---	23,447
Industrial--------------	insig.	10	214	---	---	16,120
Transportation----------	---	80	24	---	---	insig.
Electrical Generation---	18	1	51	22,301	7,000	---
Miscellaneous-----------	---	18	---	---	---	---
Synthetic Gas-----------	---	---	---	---	---	---
Total---------------	18	138	519	22,301	7,000	39,567
1980						
Household & Commercial--	insig.	32	253	---	---	35,034
Industrial--------------	insig.	11	240	---	---	23,153
Transportation----------	---	89	27	---	---	insig.
Electrical Generation---	41	4	51	22,961	7,000	---
Miscellaneous-----------	---	18	---	---	---	---
Synthetic Gas-----------	---	---	---	---	---	---
Total---------------	41	154	571	22,961	7,000	58,187
1985						
Household & Commercial--	insig.	36	271	---	---	47,479
Industrial--------------	1	15	262	---	---	30,482
Transportation----------	---	97	32	---	---	insig.
Electrical Generation---	54	7	51	23,161	14,500	---
Miscellaneous-----------	---	18	---	---	---	---
Synthetic Gas-----------	53	---	---	---	---	---
Total---------------	108	173	616	23,161	14,500	77,961
2000						
Household & Commercial--	---	45	335	---	---	83,822
Industrial--------------	2	20	338	---	---	53,634
Transportation----------	---	120	41	---	---	insig.
Electrical Generation---	130	21	51	23,161	40,000	---
Miscellaneous-----------	---	18	---	---	---	---
Synthetic Gas-----------	120	---	---	---	---	---
Total---------------	252	224	765	23,161	40,000	137,456

App. II-A. Table 8 .--North Dakota-Consumption of Energy Resources by Major Sources and Consuming Sectors
1971 actual, and projected to the year 2000
(in physical units)

	Coal (million tons)	Petroleum (million barrels)	Natural Gas (billion cu.ft.)	Hydropower (million kw-hr.)	Nuclear (million kw-hr.)	Electricity Distributed (million kw-hr.)
1971						
Household & Commercial--	0.1	5.5	17.6	---	---	2,716
Industrial--------------	0.2	1.1	16.2	---	---	472
Transportation----------	---	11.5	---	---	---	---
Electrical Generation---	3.5	0.2	0.4	3,235	---	---
Miscellaneous-----------	---	1.2	---	---	---	---
Synthetic Gas-----------	---	---	---	---	---	---
Total----------------	3.8	19.5	34.2	3,235	---	3,188
1975						
Household & Commercial--	insig.	6	19	---	---	3,810
Industrial--------------	insig.	1	16	---	---	879
Transportation----------	---	12	---	---	---	---
Electrical Generation---	5	insig.	insig.	3,000	---	---
Miscellaneous-----------	---	1	---	---	---	---
Synthetic Gas-----------	---	---	---	---	---	---
Total----------------	5	20	35	3,000	---	4,689
1980						
Household & Commercial--	insig.	6	22	---	---	5,569
Industrial--------------	insig.	1	19	---	---	1,465
Transportation----------	---	13	---	---	---	---
Electrical Generation---	13	1	insig.	3,000	---	---
Miscellaneous-----------	---	1	---	---	---	---
Synthetic Gas-----------	---	---	---	---	---	---
Total----------------	13	22	41	3,000	---	7,034
1985	insig.					
Household & Commercial--	insig.	7	24	---	---	7,620
Industrial--------------	1	2	22	---	---	1,758
Transportation----------	---	14	---	---	---	---
Electrical Generation---	19	2	insig.	3,000	---	---
Miscellaneous-----------	---	1	---	---	---	---
Synthetic Gas-----------	15	---	---	---	---	---
Total----------------	35	26	46	3,000	---	9,378
2000						
Household & Commercial--	---	8	34	---	---	12,603
Industrial--------------	1	2	29	---	---	3,517
Transportation----------	---	17	---	---	---	---
Electrical Generation---	50	6	insig.	3,000	---	---
Miscellaneous-----------	---	1	---	---	---	---
Synthetic Gas-----------	53	---	---	---	---	---
Total----------------	104	34	63	3,000	---	16,120

App.II-A. Table 9--South Dakota Consumption of Energy Resources by Major Sources and Consuming Sectors, 1971 actual, and projected to the year 2000

(in physical units)

	Coal (million tons)	Petroleum (million barrels)	Natural Gas (billion cu.ft.)	Hydropower (million kw-hr.)	Nuclear (million kw-hr.)	Electricity Distributed (million kw-hr.)
1971						
Household & Commercial--	0.1	5.9	21.3	---	---	2,792
Industrial--------------	0.2	0.6	7.3	---	---	436
Transportation----------	---	12.0	---	---	---	---
Electrical Generation---	1.2	0.2	3.3	7,742	---	---
Miscellaneous-----------	---	0.8	---	---	---	---
Synthetic Gas-----------	---	---	---	---	---	---
Total---------------	1.5	19.5	31.9	7,742	---	3,228
1975						
Household & Commercial--	insig.	6	24	---	---	3,517
Industrial--------------	insig.	1	8	---	---	586
Transportation----------	---	13	---	---	---	---
Electrical Generation---	2	insig.	3	7,300	---	---
Miscellaneous-----------	---	1	---	---	---	---
Synthetic Gas-----------	---	---	---	---	---	-----
Total---------------	2	21	35	7,300	---	4,103
1980						
Household & Commercial--	insig.	6	26	---	---	5,725
Industrial--------------	insig.	insig.	8	---	---	879
Transportation----------	---	14	---	---	---	---
Electrical Generation---	3	1	3	7,300	---	---
Miscellaneous-----------	---	1	---	---	---	---
Synthetic Gas-----------	---	---	---	---	---	---
Total---------------	3	22	37	7,300	---	6,604
1985						
Household & Commercial--	insig.	7	29	---	---	6,741
Industrial--------------	insig.	insig.	8	---	---	879
Transportation----------	---	15	---	---	---	---
Electrical Generation---	5	1	3	7,300	---	---
Miscellaneous-----------	---	1	---	---	---	---
Synthetic Gas-----------	---	---	---	---	---	---
Total---------------	5	24	40	7,300	---	7,620
2000						
Household & Commercial--	---	8	35	---	---	11,723
Industrial--------------	1	insig.	10	---	---	1,465
Transportation----------	---	16	---	---	---	---
Electrical Generation---	20	5	3	7,300	---	---
Miscellaneous-----------	---	1	---	---	---	---
Synthetic Gas-----------	---	---	---	---	---	---
Total---------------	21	30	48	7,300	---	13,188

App. II-A. Table 10.--Montana Consumption of Energy Resources by Major Sources and Consuming Sectors, 1971 actual, and projected to the year 2000

(in physical units)

	Coal (million tons)	Petroleum (million barrels)	Natural Gas (billion cu.ft.)	Hydropower (million kw-hr.)	Nuclear (million kw-hr.)	Electricity Distributed (million kw-hr.)
1971						
Household & Commercial	0.1	3.9	41.1	---	---	3,281
Industrial	0.1	2.2	49.1	---	---	6,772
Transportation	---	14.0	0.8	9,595	---	88
Electrical Generation	0.8	---	1.1	---	---	---
Miscellaneous	---	4.5	---	---	---	---
Synthetic Gas	---	---	---	---	---	---
Total	1.0	24.6	92.1	9,595	---	10,141
1975						
Household & Commercial	insig.	4	46	---	---	3,810
Industrial	insig.	3	54	---	---	9,086
Transportation	---	15	1	---	---	insig.
Electrical Generation	2	---	1	9,540	---	---
Miscellaneous	---	5	---	---	---	---
Synthetic Gas	---	---	---	---	---	---
Total	2	27	102	9,540	---	12,896
1980						
Household & Commercial	insig.	5	48	---	---	6,155
Industrial	insig.	4	61	---	---	12,016
Transportation	---	17	1	---	---	insig.
Electrical Generation	9	---	1	10,200	---	---
Miscellaneous	---	5	---	---	---	---
Synthetic Gas	---	---	---	---	---	---
Total	9	31	111	10,200	---	18,171
1985						
Household & Commercial	insig.	5	50	---	---	8,206
Industrial	insig.	6	69	---	---	14,947
Transportation	---	18	2	---	---	insig.
Electrical Generation	11	insig.	1	---	---	---
Miscellaneous	---	5	---	10,400	---	---
Synthetic Gas	23	---	---	---	---	---
Total	34	34	122	10,400	---	23,153
2000						
Household & Commercial	---	6	56	---	---	15,240
Industrial	insig.	9	84	---	---	26,377
Transportation	---	21	2	---	---	insig.
Electrical Generation	28	1	1	10,400	---	---
Miscellaneous	---	5	---	---	---	---
Synthetic Gas	45	---	---	---	---	---
Total	73	42	143	10,400	---	41,617

App. II-A. Table 11--Wyoming Consumption of Energy Resources by Major Sources and Consuming Sectors, 1971 actual, and projected to the year 2000
(in physical units)

	Coal (million tons)	Petroleum (million barrels)	Natural Gas (billion cu.ft.)	Hydropower (million kw-hr.)	Nuclear (million kw-hr.)	Electricity Distributed (million kw-hr.)
1971						
Household & Commercial--	insig.	3.4	32.4	---	---	2,028
Industrial----------	0.2	2.4	74.2	---	---	1,638
Transportation----------	---	12.8	8.0	---	---	---
Electrical Generation---	3.5	0.1	3.0	1,312	---	---
Miscellaneous----------	---	8.8	---	---	---	---
Synthetic Gas----------	---	---	---	---	---	---
Total----------	3.7	27.5	117.6	1,312	---	3,666
1975						
Household & Commercial--	insig.	4	36	---	---	2,638
Industrial----------	insig.	3	76	---	---	2,931
Transportation----------	---	12	9	---	---	---
Electrical Generation---	8	insig.	1	1,200	---	---
Miscellaneous----------	---	9	---	---	---	---
Synthetic Gas----------	---	---	---	---	---	---
Total----------	8	28	122	1,200	---	5,569
1980						
Household & Commercial--	insig.	5	42	---	---	4,396
Industrial----------	insig.	3	86	---	---	4,690
Transportation----------	---	13	10	---	---	---
Electrical Generation---	12	insig.	1	1,200	---	---
Miscellaneous----------	---	9	---	---	---	---
Synthetic Gas----------	---	---	---	---	---	---
Total----------	12	30	139	1,200	---	9,086
1985						
Household & Commercial--	insig.	5	46	---	---	6,741
Industrial----------	insig.	4	93	---	---	7,329
Transportation----------	---	15	12	---	---	---
Electrical Generation---	14	1	1	1,200	---	---
Miscellaneous----------	---	9	---	---	---	---
Synthetic Gas----------	15	---	---	---	---	---
Total----------	29	34	152	1,200	---	14,070
2000						
Household & Commercial--	---	7	58	---	---	13,482
Industrial----------	insig.	5	125	---	---	13,776
Transportation----------	---	19	17	---	---	---
Electrical Generation---	22	2	1	---	---	---
Miscellaneous----------	---	9	---	1,200	---	---
Synthetic Gas----------	23	---	---	---	---	---
Total----------	45	42	2[illegible]	1,200	---	27,258

App. II-A. Table 12--Nebraska Consumption of Energy Resources by Major Sources and Consuming Sectors, 1971 actual, and projected to the year 2000

(in physical units)

	Coal (million tons)	Petroleum (million barrels)	Natural Gas (billion cu.ft.)	Hydropower (million kw-hr.)	Nuclear (million kw-hr.)	Electricity Distributed (million kw-hr.)
1971						
Household & Commercial	insig.	8.6	94.3	---	---	7,798
Industrial	0.1	2.0	54.9	---	---	2,138
Transportation	---	25.9	13.2	---	---	---
Electrical Generation	0.9	0.2	48.9	1,359	---	---
Miscellaneous	---	1.7	---	---	---	---
Synthetic Gas	---	---	---	---	---	---
Total	1.0	38.4	211.3	1,359	---	9,936
1975						
Household & Commercial	insig.	9	105	---	---	9,672
Industrial	insig.	2	60	---	---	2,638
Transportation	---	28	14	---	---	---
Electrical Generation	1	1	46	1,261	7,000	---
Miscellaneous	---	2	---	---	---	---
Synthetic Gas	---	---	---	---	---	---
Total	1	42	225	1,261	7,000	12,310
1980						
Household & Commercial	insig.	10	115	---	---	13,189
Industrial	insig.	3	66	---	---	4,103
Transportation	---	32	16	---	---	---
Electrical Generation	4	2	46	1,261	7,000	---
Miscellaneous	---	2	---	---	---	---
Synthetic Gas	---	---	---	---	---	---
Total	4	49	243	1,261	7,000	17,292
1985						
Household & Commercial	insig.	12	122	---	---	18,171
Industrial	insig.	3	70	---	---	5,569
Transportation	---	35	18	---	---	---
Electrical Generation	5	3	46	1,261	14,500	---
Miscellaneous	---	2	---	---	---	---
Synthetic Gas	---	---	---	---	---	---
Total	5	55	256	1,261	14,500	23,740
2000						
Household & Commercial	insig.	16	152	---	---	30,774
Industrial	insig.	4	90	---	---	8,499
Transportation	---	45	22	---	---	---
Electrical Generation	10	7	46	1,261	40,000	---
Miscellaneous	---	2	---	---	---	---
Synthetic Gas	---	---	---	---	---	---
Total	10	74	310	1,261	40,000	39,273

Table 13 .--Northern Great Plains Region - Demand for Energy Inputs to Household and Commercial Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons----------------------	0.3	insig.	insig.	insig.	-
Trillion Btu----------------------	9.0	6	4	1	-
Percent of total sector inputs----	2.1	1.3	0.7	0.2	0
Petroleum:					
Million barrels-------------------	27.3	29	32	36	45
Trillion Btu----------------------	145.0	152	167	182	229
Percent of total sector inputs----	33.7	32.0	30.3	29.1	26.6
Natural Gas:					
Billion cu.ft.--------------------	206.7	230	253	271	335
Trillion Btu----------------------	213.0	237	262	280	346
Percent of total sector inputs----	49.5	49.9	47.5	44.8	40.2
Electricity Purchased:					
Million Kwhr----------------------	18,615	23,447	35,034	47,479	83,822
Trillion Btu----------------------	63.5	80	118	162	286
Percent of total sector inputs----	14.8	16.8	21.4	25.9	33.2
Total Sector Inputs:					
Trillion Btu----------------------	430.5	475	551	625	861
Percent of national total sector inputs-------------------	2.5	2.4	2.3	2.3	2.2
Total National Sector Inputs: 1/					
Trillion Btu----------------------	17,441	20,175	23,860	27,700	39,630

1/ U.S. Energy Through the Year 2000, U.S. Dept. of Interior.

NOTE: Percentages may not add to 100 due to rounding.

Table 14 .--North Dakota Demand for Energy Inputs to Household and Commerical Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons----------------------	0.1	insig.	insig.	insig.	-
Trillion Btu----------------------	2.8	2	1	insig.	-
Percent of total sector inputs----	4.6	3.0	1.3	0	0
Petroleum:					
Million barrels-------------------	5.5	6	6	7	8
Trillion Btu----------------------	30.5	32	34	36	42
Percent of total sector inputs----	50.2	47.8	44.2	41.4	35.0
Natural Gas:					
Billion cu.ft.--------------------	17.6	19	22	24	34
Trillion Btu----------------------	18.1	20	23	25	35
Percent of total sector inputs----	29.8	29.8	29.8	28.7	29.2
Electricity Purchased:					
Million Kwhr----------------------	2,716	3,810	5,569	7,620	12,603
Trillion Btu----------------------	9.3	13	19	26	43
Percent of total sector inputs----	15.3	19.4	24.7	29.9	35.8
Total Sector Inputs:					
Trillion Btu----------------------	60.7	67	77	87	120
Percent of national total sector inputs-------------------	14.1	14.1	14.0	13.9	13.9
Total National Sector Inputs:					
Trillion Btu----------------------	430.5	475	551	625	861

NOTE: Percentages may not add to 100 due to rounding.

Table 15 -South Dakota Demand for Energy Inputs to Household and Commercial Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons	0.1	insig.	insig.	insig.	-
Trillion Btu	1.2	1	1	insig.	-
Percent of total sector inputs	1.9	1.4	1.3	insig.	-
Petroleum:					
Million barrels	5.9	6	6	7	8
Trillion Btu	30.7	31	32	34	38
Percent of total sector inputs	48.5	44.9	41.0	39.1	33.3
Natural Gas:					
Billion cu.ft.	21.3	24	26	29	35
Trillion Btu	21.9	25	27	30	36
Percent of total sector inputs	34.6	36.2	34.6	34.5	31.6
Electricity Purchased:					
Million Kwhr	2,792	3,517	5,725	6,741	11,723
Trillion Btu	9.5	12	18	23	40
Percent of total sector inputs	15.0	17.4	23.1	26.4	35.1
Total Sector Inputs:					
Trillion Btu	63.3	69	78	87	114
Percent of national total sector inputs	14.7	14.5	14.2	13.9	13.2
Total National Sector Inputs:					
Trillion Btu	430.5	475	551	625	861

NOTE: Percentages may not add to 100 due to rounding.

Table 16 .--Montana Demand for Energy Inputs to Household and Commercial Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons	0.1	insig.	insig.	insig.	-
Trillion Btu	3.7	3	2	1	-
Percent of total sector inputs	4.6	3.4	2.0	0.9	-
Petroleum:					
Million barrels	3.9	4	5	5	6
Trillion Btu	22.4	24	26	28	35
Percent of total sector inputs	28.1	27.6	26.3	25.7	24.1
Natural Gas:					
Billion cu.ft.	41.1	46	48	50	56
Trillion Btu	42.3	47	50	52	58
Percent of total sector inputs	53.1	54.0	50.5	47.7	40.0
Electricity Purchased:					
Million Kwhr	3,281	3,810	6,155	8,206	15,240
Trillion Btu	11.2	13	21	28	52
Percent of total sector inputs	14.1	14.9	21.2	25.7	35.9
Total Sector Inputs:					
Trillion Btu	79.6	87	99	109	145
Percent of national total sector inputs	18.5	18.3	18.0	17.4	16.8
Total National Sector Inputs:					
Trillion Btu	430.5	475	551	625	861

NOTE: Percentages may not add to 100 due to rounding.

Table 17 .--Wyoming Demand for Energy Inputs to Household and Commercial Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons	insig.	insig.	insig.	insig.	-
Trillion Btu	0.7	insig.	insig.	insig.	-
Percent of total sector inputs	1.2	insig.	insig.	insig.	-
Petroleum:					
Million barrels	3.4	4	5	5	7
Trillion Btu	18.4	20	23	26	36
Percent of total sector inputs	31.0	30.3	28.4	27.0	25.4
Natural Gas:					
Billion cu.ft.	32.4	36	42	46	58
Trillion Btu	33.4	37	43	47	60
Percent of total sector inputs	56.2	56.1	53.1	49.0	42.2
Electricity Purchased:					
Million Kwhr	2,028	2,638	4,396	6,741	13,482
Trillion Btu	6.9	9	15	23	46
Percent of total sector inputs	11.6	13.6	18.5	24.0	32.4
Total Sector Inputs:					
Trillion Btu	59.4	66	81	96	142
Percent of national total sector inputs	13.8	13.9	14.7	15.4	16.5
Total National Sector Inputs:					
Trillion Btu	430.5	475	551	625	861

NOTE: Percentages may not add to 100 due to rounding.

Table 18 .--Nebraska Demand for Energy Inputs to Household and Commercial Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons	insig.	insig.	insig.	insig.	-
Trillion Btu	0.6	insig.	insig.	insig.	-
Percent of total sector inputs	0.4	0	0	0	0
Petroleum:					
Million barrels	8.6	9	10	12	16
Trillion Btu	43.0	45	52	58	78
Percent of total sector inputs	25.7	24.3	24.1	23.6	22.9
Natural Gas:					
Billion cu.ft.	94.3	105	115	122	152
Trillion Btu	97.3	108	119	126	157
Percent of total sector inputs	58.1	58.4	55.1	51.2	46.2
Electricity Purchased:					
Million Kwhr	7,798	9,672	13,189	18,171	30,774
Trillion Btu	26.6	33	45	62	105
Percent of total sector inputs	15.9	17.8	20.8	25.2	30.9
Total Sector Inputs:					
Trillion Btu	167.5	185	216	246	340
Percent of national total sector inputs	38.9	38.9	39.2	39.4	39.5
Total National Sector Inputs:					
Trillion Btu	430.5	475	551	625	861

NOTE: Percentages may not add to 100 due to rounding.

Table 19. Northern Great Plains Region - Demand for Energy Inputs to Industrial Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons	0.8	insig.	insig.	1	2
Trillion Btu	21.6	23	24	25	33
Percent of Total sector input	6.8	6.5	5.7	5.2	4.8
Petroleum:					
Million barrels	8.3	10	11	15	20
Trillion Btu	47.9	57	68	82	122
Percent of total sector input	15.1	16.0	16.2	17.0	17.8
Natural gas:					
Billion cu.ft.	201.7	214	240	262	338
Trillion Btu	207.7	221	248	270	349
Percent of total sector input	65.7	62.1	59.2	56.1	50.8
Electricity Purchased:					
Million Kwhr	11,456	16,120	23,153	30,482	53,634
Trillion Btu	39.1	55	79	104	183
Percent of total sector input	12.4	15.4	18.9	21.6	26.6
Total Sector Inputs:					
Trillion Btu	316.3	356	419	481	687
Percent of national total sector inputs	1.4	1.4	1.4	1.4	1.2
Total National Sector Inputs 1/					
Trillion Btu	22,263	25,860	29,390	34,870	57,780

1/ U.S. Energy Through the Year 2000, U.S. Dept. of Interior

NOTE: Percentages may not add to 100 due to rounding.

Table 20. North Dakota Demand for Energy Inputs to Industrial Sector,
1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons	0.2	insig.	insig.	1	1
Trillion Btu	6.5	7	7	8	10
Percent of Total sector input	21.0	20.6	17.5	17.4	15.9
Petroleum:					
Million barrels	1.1	1	1	2	2
Trillion Btu	6.2	7	8	9	11
Percent of total sector input	20.0	20.6	20.0	19.6	17.5
Natural gas:					
Billion cu.ft.	16.2	16	19	22	29
Trillion Btu	16.7	17	20	23	30
Percent of total sector input	53.8	50.0	50.0	50.0	47.6
Electricity Purchased:					
Million Kwhr	472	879	1,465	1,758	3,517
Trillion Btu	1.6	3	5	6	12
Percent of total sector input	5.2	8.8	12.5	13.0	19.0
Total Sector Inputs:					
Trillion Btu	31.0	34	40	46	63
Percent of total sector inputs	9.8	9.6	9.5	9.6	9.2
Total Region Sector Inputs:					
Trillion Btu	316.3	356	419	481	687

NOTE: Percentages may not add to 100 due to rounding.

Table 21. South Dakota Demand for Energy Inputs to Industrial Sector, 1971 Actual, and Projected to the Year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons	0.2	insig.	insig.	insig.	1
Trillion Btu	5.1	5	6	6	8
Percent of Total sector input	29.5	27.8	31.6	31.6	32.0
Petroleum:					
Million barrels	0.6	1	insig.	insig.	insig.
Trillion Btu	3.2	3	2	2	2
Percent of total sector input	18.5	16.7	10.5	10.5	8.0
Natural gas:					
Billion cu.ft.	7.3	8	8	8	10
Trillion Btu	7.5	8	8	8	10
Percent of total sector input	43.4	44.4	42.1	42.1	40.0
Electricity Purchased:					
Million Kwhr	436	586	879	879	1,465
Trillion Btu	1.5	2	3	3	5
Percent of total sector input	8.7	11.1	15.8	15.8	20.0
Total Sector Inputs:					
Trillion Btu	17.3	18	19	19	25
Percent of region total sector inputs	5.5	5.1	4.5	4.0	3.6
Total Region Sector Inputs:	316.3	356	419	481	687
Trillion Btu					

NOTE: Percentages may not add to 100 due to rounding.

Table 22. Montana Demand for Energy Inputs to Industrial Sector, 1971 Actual, and Projected to the Year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons	0.1	insig.	insig.	insig.	insig.
Trillion Btu	1.1	1	1	1	2
Percent of Total sector input	1.3	0.9	0.8	0.6	0.9
Petroleum:					
Million barrels	2.2	3	4	6	9
Trillion Btu	13.1	18	25	33	55
Percent of total sector input	14.9	17.0	19.2	21.2	23.5
Natural gas:					
Billion cu.ft.	49.1	54	61	69	84
Trillion Btu	50.5	56	63	71	87
Percent of total sector input	57.5	52.8	48.5	45.5	37.2
Electricity Purchased:					
Million Kwhr	6,772	9,086	12,016	14,947	26,377
Trillion Btu	23.1	31	41	51	90
Percent of total sector input	26.3	29.3	31.5	32.7	38.4
Total Sector Inputs:					
Trillion Btu	87.8	106	130	156	234
Percent of region total sector inputs	27.8	29.8	31.0	32.4	34.1
Total Region Sector Inputs:					
Trillion Btu	316.3	356	419	481	687

NOTE: Percentages may not add to 100 due to rounding.

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Table 23. Wyoming Demand for Energy Inputs to Industrial Sector, 1971 Actual, and Projected to the Year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons	0.2	insig.	insig.	insig.	insig.
Trillion Btu	4.5	5	5	5	7
Percent of Total sector input	4.5	4.6	3.9	3.4	3.3
Petroleum:					
Million barrels	2.4	3	3	4	5
Trillion Btu	14.0	16	19	21	30
Percent of total sector input	13.9	14.7	14.7	14.3	14.1
Natural gas:					
Billion cu.ft.	74.2	76	86	93	125
Trillion Btu	76.5	78	89	96	129
Percent of total sector input	76.0	71.5	69.0	65.3	60.5
Electricity Purchased:					
Million Kwhr	1,638	2,931	4,690	7,329	13,776
Trillion Btu	5.6	10	16	25	47
Percent of total sector input	5.6	9.2	12.4	17.0	22.1
Total Sector Inputs:					
Trillion Btu	100.6	109	129	147	213
Percent of region total sector inputs	31.8	30.6	30.8	30.6	31.0
Total Region Sector Inputs:					
Trillion Btu	316.3	356	419	481	687

NOTE: Percentages may not add to 100 due to rounding.

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Table 24. Nebraska - Demand for Energy Inputs to Industrial Sector, 1971 Actual, and Projected to the Year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons-------------------------	0.1	insig.	insig.	insig.	insig.
Trillion Btu-------------------------	4.4	5	5	5	6
Percent of Total sector input---------	5.5	5.6	5.0	4.4	3.9
Petroleum:					
Million barrels----------------------	2.0	2	3	3	4
Trillion Btu-------------------------	11.4	13	14	17	24
Percent of total sector input---------	14.3	14.6	13.9	15.0	15.8
Natural gas:					
Billion cu.ft.-----------------------	54.9	60	66	70	90
Trillion Btu-------------------------	56.5	62	68	72	93
Percent of total sector input---------	71.0	69.7	67.3	63.7	59.2
Electricity Purchased:					
Million Kwhr-------------------------	2,138	2,638	4,103	5,569	8,499
Trillion Btu-------------------------	7.3	9	14	19	29
Percent of total sector input---------	9.2	10.1	13.9	16.8	19.1
Total Sector Inputs:					
Trillion Btu-------------------------	79.6	89	101	113	152
Percent of total region sector inputs---------------------	25.2	25.0	24.1	23.5	22.1
Total Region Sector Inputs:					
Trillion Btu-------------------------	316.3	356	419	481	687

NOTE: Percentages may not add to 100 due to rounding.

Table 25. Northern Great Plains Region - Demand for Energy Inputs to the Transportation Sector, 1971 actual and projected to the year 2000

	1971	1975	1980	1985	2000
Petroleum:					
Million barrels	76.2	80	89	97	120
Trillion Btu	399.1	430	477	520	652
Percent of total sector input	94.5	94.5	94.5	94.0	93.8
Natural Gas:					
Billion cu. ft.	22.0	24	27	32	41
Trillion Btu	22.9	25	28	33	43
Percent of total sector input	5.4	5.5	5.5	6.0	6.2
Electricity purchased:					
Million kwhr	88	insig.	insig.	insig.	insig.
Trillion Btu	0.3	insig.	insig.	insig.	insig.
Percent of total sector input	0.1	insig.	insig.	insig.	insig.
Total Sector Energy Inputs:					
Trillion Btu	422.3	455	505	553	695
Percent of total national sector inputs	2.5	2.4	2.2	2.0	1.6
National Total Sector Inputs:[1]					
Trillion Btu	16,989	19,090	22,870	27,130	42,660

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[1] From "U.S. Energy to the Year 2000," U.S. Dept. of the Interior.

NOTE: Percentages may not add to 100 due to rounding.

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Table 26. North Dakota - Demand for Energy Inputs to the Transportation Sector, 1971 Actual, and Projected to the Year 2000

	1971	1975	1980	1985	2000
Petroleum:					
Million Barrels	11.5	12	13	14	17
Trillion Btu	61.2	67	72	77	91
Percent of total sector input	100.0	100.0	100.0	100.0	100.0
Natural Gas:					
Billion cu. ft.	-	-	-	-	-
Trillion Btu	-	-	-	-	-
Percent of total sector input	0	0	0	0	0
Electricity purchased:					
Million kwhr	-	-	-	-	-
Trillion Btu	-	-	-	-	-
Percent of total sector input	0	0	0	0	0
Total Sector Energy Inputs:					
Trillion Btu	61.2	67	72	77	91
Percent of Region total sector inputs	14.5	14.7	14.3	13.9	13.1
Region Total Sector Inputs:					
Trillion Btu	422.3	455	505	553	695

NOTE: Percentages may not add to 100 due to rounding.

Table 27. South Dakota's Demand for Energy Inputs to the Transportation Sector, 1971 Actual, and Projections to the Year 2000

	1971	1975	1980	1985	2000
Petroleum:					
Million barrels-------------------	12.0	13	14	15	16
Trillion Btu----------------------	64.1	69	75	80	95
Percent of total sector input	100.0	100.0	100.0	100.0	100.0
Natural Gas:					
Billion cu. ft.-------------------	-	-	-	-	-
Trillion Btu----------------------	-	-	-	-	-
Percent of total sector input-----	0	0	0	0	0
Electricity purchased:					
Million kwhr----------------------	-	-	-	-	-
Trillion Btu----------------------	-	-	-	-	-
Percent of total sector input-----	0	0	0	0	0
Total Sector Energy Inputs:					
Trillion Btu----------------------	64.1	69	75	80	95
Percent of Region Total sector inputs-------------------------	15.2	15.2	14.9	14.5	13.7
Region Total Sector Inputs:					
Trillion Btu----------------------	422.3	455	505	553	695

NOTE: Percentages may not add to 100 due to rounding.

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Table 28. Montana Demand for Energy Inputs to the Transportation Sector, 1971 Actual, and Projections to the Year 2000

	1971	1975	1980	1985	2000
Petroleum:					
Million barrels	14.0	15	17	18	21
Trillion Btu	76.4	83	90	96	116
Percent of total sector inputs	98.3	98.8	98.9	98.0	98.3
Natural Gas:					
Billion cu ft.	0.8	1	1	2	2
Trillion cu. ft.	1.0	1	1	2	2
Percent of total sector inputs	1.3	1.2	1.1	2.0	1.7
Electricity purchased:					
Million kwhr	88	insig.	insig.	insig.	insig.
Trillion Btu	0.3	insig.	insig.	insig.	insig.
Percent of total sector inputs	0.4	insig.	insig.	insig.	insig.
Total Sector Input:					
Trillion Btu	77.7	84	91	98	118
Percent of Region total sector inputs	18.4	18.5	18.0	17.7	17.0
Total Region Sector Inputs:					
Trillion Btu	422.3	455	505	553	695

NOTE: Percentage may not add to 100 due to rounding.

Table 29. Wyoming Demand for Energy Inputs to the Transportation Sector, 1971 Actual, and Projections to the Year 2000

	1971	1975	1980	1985	2000
Petroleum:					
Million barrels	12.8	12	13	15	19
Trillion Btu	59.1	63	73	82	109
Percent of total sector input	87.8	87.5	88.0	87.2	85.8
Natural Gas:					
Billion cu. ft.	8.0	9	10	12	17
Trillion Btu	8.2	9	10	12	18
Percent of total sector input	12.2	12.5	12.0	12.8	14.2
Electricity purchased:					
Million kwhr	-	-	-	-	-
Trillion Btu	-	-	-	-	-
Percent of total sector input	0	0	0	0	0
Total Sector Energy Inputs:					
Trillion Btu	67.3	72	83	94	127
Percent of Region Total sector input	15.9	15.8	16.4	17.0	18.3
Region Total Sector Input:					
Trillion Btu	422.3	455	505	553	695

NOTE: Percentages may not add to 100 due to rounding.

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Table 30. Nebraska - Demand for Energy Inputs to the Transportation Sector, 1971 Actual, and Projected to the Year 2000

	1971	1975	1980	1985	2000
Petroleum:					
Million barrels	25.9	28	32	35	45
Trillion Btu	138.3	148	167	185	241
Percent of total sector input	91.0	90.8	90.8	90.7	91.3
Natural Gas:					
Billion cu. ft.	13.2	14	16	18	22
Trillion Btu	13.7	15	17	19	23
Percent of total sector input	9.0	9.2	9.2	9.3	8.7
Electricity purchased:					
Million kwhr	-	-	-	-	-
Trillion Btu	-	-	-	-	-
Percent of total sector input	0	0	0	0	0
Total Sector Energy Inputs:					
Trillion Btu	152.0	163	184	204	264
Percent of Region Total Sector input	36.0	35.8	36.4	36.9	37.9
Region Total Sector Inputs:					
Trillion Btu	422.3	455	505	553	695

NOTE: Percentages may not add to 100 due to rounding.

Table 31. Northern Great Plains Region-- Electric Utility Industry Installed Generating Capacity, Net Generation, Load Factor 1971 actual, and projected to the year 2000

Year	Installed Generating Capacity (Mw)	Load Factor (percent)	Net Generation Million Kwhr	Net Generation Trillion Btu
1971:				
Fuel burning plants 1/—	4,591	45.5	18,294	62.4
Nuclear plants----------	0	0	0	0
Hydropower plants-------	3,756	70.6	23,242	79.2
Total 2/-------------	8,347	56.8	41,536	141.6
1975:				
Fuel burning plants-----	7,505	42.2	27,759	89
Nuclear plants----------	1,265	63.2	7,000	24
Hydropower plants-------	4,000	63.6	22,301	76
Total----------------	12,770	51.0	57,060	189
1980:				
Fuel burning plants-----	12,615	59.0	65,239	223
Nuclear plants----------	1,285	62.2	7,000	24
Hydropower plants-------	4,242	61.8	22,961	78
Total----------------	18,142	59.9	95,200	325
1985:				
Fuel burning plants-----	16,483	58.2	84,066	287
Nuclear plants----------	2,700	61.3	14,500	50
Hydropower plants-------	4,363	60.6	23,161	79
Total----------------	23,546	59.0	121,727	416
2000:				
Fuel burning plants-----	46,785	61.9	253,559	866
Nuclear plants----------	6,600	69.2	40,000	136
Hydropower plants-------	4,363	60.6	23,161	79
Total----------------	57,748	62.6	316,720	1,081

1/ Fuel burning plants include steam, internal combustion and gas turbine plants.
2/ Based on FPC projections by State through the year 2000.

Table 32. North Dakota-- Electric Utility Industry-Installed Generating Capacity, Net Generation, and Load Factor, 1971 actual, and projected to the year 2000

Year	Installed Generating Capacity (Mw)	Load Factor (percent)	Net Generation	
			Million Kwhr	Trillion Btu
1971:				
Fuel burning plants 1/--	908	63.3	5,033	17.2
Nuclear plants----------	0	0	0	0
Hydropower plants-------	400	92.3	3,235	11.0
Total 2/------------	1,308	72.2	8,268	28.2
1975:				
Fuel burning plants-----	1,278	52.3	5,850	13
Nuclear plants----------	0	0	0	0
Hydropower plants-------	400	85.6	3,000	10
Total----------------	1,678	60.2	8,850	23
1980:				
Fuel burning plants-----	3,033	68.1	18,090	62
Nuclear plants----------	0	0	0	0
Hydropower plants-------	400	85.6	3,000	10
Total----------------	3,433	70.1	21,090	72
1985:				
Fuel burning plants-----	4,125	67.0	24,210	83
Nuclear plants----------	0	0	0	0
Hydropower plants-------	400	85.6	3,000	10
Total----------------	4,525	68.6	27,210	93
2000:				
Fuel burning plants-----	14,910	64.1	83,710	286
Nuclear plants----------	0	0	0	0
Hydropower plants-------	400	85.6	3,000	10
Total----------------	15,310	64.7	86,710	296

1/ Fuel burning plants include steam, internal combustion and gas turbine plants.
2/ Based on FPC projections by State through the year 2000.

Table 34. South Dakota--Electric Utility Industry-Installed Generating Capacity, Net Generation, and Load Factor, 1971 actual, and projected to the tear 2000

Year	Installed Generating Capacity (Mw)	Load Factor (percent)	Net Generation Million Kwhr	Net Generation Trillion Btu
1971:				
Fuel burning plants 1/--	332	22.3	650	2.2
Nuclear plants----------	0	0	0	0
Hydropower plants-------	1,384	63.8	7,741	26.4
Total 2/------------	1,716	55.8	8,391	28.6
1975:				
Fuel burning plants-----	764	28.5	1,910	7
Nuclear plants----------	0	0	0	0
Hydropower plants-------	1,384	60.2	7,300	25
Total---------------	2,148	48.9	9,210	32
1980:				
Fuel burning plants-----	794	46.9	3,260	11
Nuclear plants----------	0	0	0	0
Hydropower plants-------	1,384	60.2	7,300	25
Total---------------	2,178	55.3	10,560	36
1985:				
Fuel burning plants-----	1,504	53.4	7,040	24
Nuclear plants----------	0	0	0	0
Hydropower plants-------	1,384	60.2	7,300	25
Total---------------	2,888	56.7	14,340	49
2000:				
Fuel burning plants-----	6,060	60.5	32,100	110
Nuclear plants----------	0	0	0	0
Hydropower plants-------	1,384	60.2	7,300	25
Total---------------	7,444	60.4	39,400	135

1/ Fuel burning plants include steam, internal combustion and gas turbine plants.
2/ Based on FPC projections by State through the year 2000.

Table 34. Montana--Electric Utility Industry-Installed Generating Capacity, Net Generation, and Load Factor, 1971 actual, and projected to the year 2000

Year	Installed Generating Capacity (Mw)	Load Factor (percent)	Net Generation Million Kwhr	Net Generation Trillion Btu
1971:				
Fuel burning plants 1/--	320	37.7	1,058	3.6
Nuclear plants----------	0	0	0	0
Hydropower plants-------	1,512	72.4	9,595	32.7
Total 2/------------	1,832	66.4	10,653	36.3
1975:				
Fuel burning plants-----	695	36.0	2,190	8
Nuclear plants----------	0	0	0	0
Hydropower plants-------	1,754	62.1	9,540	33
Total---------------	2,449	54.7	11,730	41
1980:				
Fuel burning plants-----	2,425	63.6	13,520	46
Nuclear plants----------	0	0	0	0
Hydropower plants-------	1,996	58.3	10,200	35
Total---------------	4,421	61.2	23,720	81
1985:				
Fuel burning plants-----	3,101	64.1	17,410	59
Nuclear plants----------	0	0	0	0
Hydropower plants-------	2,117	56.1	10,400	36
Total---------------	5,218	60.8	27,810	95
2000:				
Fuel burning plants-----	9,100	53.1	42,350	145
Nuclear plants----------	0	0	0	0
Hydropower plants-------	2,117	56.1	10,400	36
Total---------------	11,217	53.7	52,750	181

1/ Fuel burning plants include steam, internal combustion and gas turbine plants.
2/ Based on FPC projections by State through the year 2000.

Table 35. Wyoming--Electric Utility Industry-Installed Generating Capacity, Net Generation, and Load Factor, 1971 actual, and projected to the year 2000

Year	Installed Generating Capacity (Mw)	Load Factor (percent)	Net Generation Million Kwhr	Net Generation Trillion Btu
1971:				
Fuel burning plants 1/--	1,254	46.8	5,146	17.5
Nuclear plants----------	0	0	0	0
Hydropower plants-------	222	67.5	1,312	4.5
Total 2/-------------	1,476		6,458	22.0
1975:				
Fuel burning plants-----	2,563	56.9	12,770	44
Nuclear plants----------	0	0	0	0
Hydropower plants-------	222	61.7	1,200	4
Total----------------	2,785	57.3	13,970	48
1980:				
Fuel burning plants-----	3,393	65.0	19,330	66
Nuclear plants----------	0	0	0	0
Hydropower plants-------	222	61.7	1,200	4
Total----------------	3,615	64.8	20,530	70
1985:				
Fuel burning plants-----	3,893	65.0	22,167	76
Nuclear plants----------	0	0	0	0
Hydropower plants-------	222	61.7	1,200	4
Total----------------	4,115	64.8	23,367	80
2000:				
Fuel burning plants-----	8,455	63.0	46,660	159
Nuclear plants----------	0	0	0	0
Hydropower plants-------	222	61.7	1,200	4
Total----------------	8,677	63.0	47,860	163

1/ Fuel burning plants include steam, internal combustion and gas turbine plants.
2/ Based on FPC projections by State through the year 2000.

Table 36. **Nebraska--Electric Utility Industry-Installed Generating Capacity, Net Generation, and Load Factor, 1971 actual, and projected to the year 2000**

Year	Installed Generating Capacity (Mw)	Load Factor (percent)	Net Generation Million Kwhr	Net Generation Trillion Btu
1971:				
Fuel burning plants 1/--	1,777	41.2	6,407	21.9
Nuclear plants----------	0	0	0	0
Hydropower plants-------	238	65.2	1,359	4.6
Total 2/------------	2,015	44.0	7,766	26.5
1975:				
Fuel burning plants-----	2,205	26.1	5,039	17
Nuclear plants----------	1,265	63.2	7,000	24
Hydropower plants-------	240	60.0	1,261	4
Total----------------	3,710	40.9	13,300	45
1980:				
Fuel burning plants-----	2,970	42.0	11,039	38
Nuclear plants----------	1,285	62.2	7,000	24
Hydropower plants-------	240	60.0	1,261	4
Total----------------	4,495	49.0	19,300	66
1985:				
Fuel burning plants-----	3,860	39.2	13,239	45
Nuclear plants----------	2,700	61.3	14,500	50
Hydropower plants-------	240	60.0	1,261	4
Total----------------	6,800	49.0	29,000	99
2000:				
Fuel burning plants-----	8,260	67.4	48,739	166
Nuclear plants----------	6,600	69.2	40,000	136
Hydropower plants-------	240	60.0	1,261	4
Total----------------	15,100	68.0	90,000	306

1/ Fuel burning plants include steam, internal combustion and gas turbine plants.
2/ Based on FPC projections by State through the year 2000.

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Table 37 .--Northern Great Plains Region - Demand for Energy Inputs to the Electric Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons----------------------	9.9	18	41	54	130
Trillion Btu----------------------	220.1	270	615	810	1,950
Percent of total sector inputs----	42.3	42.7	62.4	63.8	72.6
Petroleum:					
Million barrels-------------------	0.7	1	4	7	21
Trillion Btu----------------------	4.7	8	24	24	126
Percent of total sector inputs----	0.9	1.3	2.4	3.3	4.7
Natural Gas:					
Billion cu.ft.--------------------	56.7	51	51	51	51
Trillion Btu----------------------	58.4	52	52	52	52
Percent of total sector inputs----	11.2	8.2	5.3	4.1	1.9
Hydropower:					
Million Kwhr----------------------	23,243	22,301	22,961	23,161	23,161
Trillion Btu----------------------	237.6	228	219	214	197
Percent of total sector inputs----	45.6	36.0	22.2	16.9	7.3
Nuclear:					
Million Kwhr----------------------	-	7,000	7,000	14,500	40,000
Trillion Btu----------------------	-	75	75	151	360
Percent of total sector inputs----	0	11.8	7.6	11.9	13.4
Total Sector Inputs:					
Trillion Btu----------------------	520.8	633	985	1,269	2,685
Percent of national total sector inputs------------------	3.0	2.8	3.2	3.1	3.3
Total National Sector Inputs:					
Trillion Btu----------------------	17,443	22,410	29,970	40,390	80,380

NOTE: Percentages may not add to 100 due to rounding.

Table 38. .--North Dakota Demand for Energy Inputs to the Electric Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons----------------------	3.5	5	13	19	50
Trillion Btu----------------------	78.4	75	195	285	750
Percent of total sector inputs----	69.2	70.1	84.8	87.7	92.4
Petroleum:					
Million barrels-------------------	0.2	insig.	1	2	6
Trillion Btu----------------------	1.3	1	6	12	36
Percent of total sector inputs----	1.1	0.9	2.6	3.7	4.4
Natural Gas:					
Billion cu.ft.--------------------	0.4	insig.	insig.	insig.	insig.
Trillion Btu----------------------	0.4	insig.	insig.	insig.	insig.
Percent of total sector inputs----	0.4	insig.	insig.	insig.	insig.
Hydropower:					
Million Kwhr----------------------	3,235	3,000	3,000	3,000	3,000
Trillion Btu----------------------	33.2	31	29	28	26
Percent of total sector inputs----	29.3	29.0	12.6	8.6	3.2
Total Sector Inputs:					
Trillion Btu----------------------	113.3	107	230	325	812
Percent of region total sector inputs------------------	21.8	16.9	23.4	25.6	30.2
Total Region Sector Inputs:					
Trillion Btu----------------------	520.8	633	985	1,269	2,685

NOTE: Percentages may not add to 100 due to rounding.

Table 39. --South Dakota Demand for Energy Inputs to the Electric Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons----------------------	1.2	2	3	5	20
Trillion Btu----------------------	26.1	30	45	75	300
Percent of total sector inputs----	23.7	27.5	36.2	49.7	75.9
Petroleum:					
Million barrels-------------------	0.2	insig.	1	1	5
Trillion Btu----------------------	1.4	1	6	6	30
Percent of total sector inputs----	1.3	0.9	4.8	4.0	7.6
Natural Gas:					
Billion cu.ft.--------------------	3.3	3	3	3	3
Trillion Btu----------------------	3.4	3	3	3	3
Percent of total sector inputs----	3.1	2.8	2.4	2.0	0.8
Hydropower:					
Million Kwhr----------------------	7,742	7,300	7,300	7,300	7,300
Trillion Btu----------------------	79.3	75	70	67	62
Percent of total sector inputs----	72.0	68.8	56.5	44.4	15.7
Total Sector Inputs:					
Trillion Btu----------------------	110.2	109	124	151	395
Percent of region total sector inputs------------------	21.2	17.2	12.6	11.9	14.7
Total Region Sector Inputs:					
Trillion Btu----------------------	520.8	633	985	1,269	2,685

NOTE: Percentages may not add to 100 due to rounding.

Table 40. .--Montana Demand for Energy Inputs to the Electric Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons----------------------	0.8	2	9	11	28
Trillion Btu----------------------	17.4	30	135	165	420
Percent of total sector inputs----	14.9	23.4	57.9	63.0	81.6
Petroleum:					
Million barrels------------------	--	--	--	insig.	1
Trillion Btu----------------------	--	--	--	insig.	6
Percent of total sector inputs----	0	0	0	insig.	1.2
Natural Gas:					
Billion cu.ft.--------------------	1.1	1	1	1	1
Trillion Btu----------------------	1.1	1	1	1	1
Percent of total sector inputs----	0.9	0.8	0.4	0.4	0.2
Hydropower:					
Million Kwhr----------------------	9,595	9,540	10,200	10,400	10,400
Trillion Btu----------------------	98.3	97	97	96	88
Percent of total sector inputs----	84.2	75.8	41.6	36.6	17.1
Total Sector Inputs:					
Trillion Btu----------------------	116.8	128	233	262	515
Percent of region total sector inputs------------------	22.4	20.2	23.7	20.7	19.2
Total Region Sector Inputs:					
Trillion Btu----------------------	520.8	633	985	1,269	2,685

NOTE: Percentages may not add to 100 due to rounding.

Table 41. .--Wyoming Demand for Energy Inputs to the Electric Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons----------------------	3.5	8	12	14	22
Trillion Btu----------------------	78.4	120	180	210	330
Percent of total sector inputs----	82.2	90.2	93.8	92.1	93.5
Petroleum:					
Million barrels-------------------	0.1	insig.	insig.	1	2
Trillion Btu----------------------	0.5	insig.	insig.	6	12
Percent of total sector inputs----	0.5	insig.	insig.	2.6	3.4
Natural Gas:					
Billion cu.ft.--------------------	3.0	1	1	1	1
Trillion Btu----------------------	3.1	1	1	1	1
Percent of total sector inputs----	3.2	0.8	0.5	0.4	0.3
Hydropower:					
Million Kwhr----------------------	1,312	1,200	1,200	1,200	1,200
Trillion Btu----------------------	13.4	12	11	11	10
Percent of total sector inputs----	14.0	9.0	5.7	4,8	2.8
Total Sector Inputs:					
Trillion Btu----------------------	95.4	133	192	228	353
Percent of region total sector inputs-------------------	18.3	21.0	19.5	18.0	13.2
Total Region Sector Inputs:					
Trillion Btu----------------------	520.8	633	985	1,269	2,685

NOTE: Percentages may not add to 100 due to rounding.

Table 42. .--Nebraska Demand for Energy Inputs to the Electric Sector, 1971 actual, and projected to the year 2000

	1971	1975	1980	1985	2000
Coal:					
Million tons---------------------	0.9	1	4	5	10
Trillion Btu---------------------	19.8	15	60	75	150
Percent of total sector inputs----	23.3	9.6	29.1	24.8	24.6
Petroleum:					
Million barrels------------------	0.2	1	2	3	7
Trillion Btu---------------------	1.5	6	12	18	42
Percent of total sector inputs----	1.8	3.8	5.8	5.9	6.9
Natural Gas:					
Billion cu.ft.-------------------	48.9	46	46	46	46
Trillion Btu---------------------	50.4	47	47	47	47
Percent of total sector inputs----	59.2	30.1	22.8	15.5	7.7
Hydropower:					
Million Kwhr---------------------	1,359	1,261	1,261	1,261	1,261
Trillion Btu---------------------	13.4	13	12	12	11
Percent of total sector inputs----	15.8	8.3	5.8	4.0	1.8
Nuclear:					
Million Kwhr---------------------	--	7,000	7,000	14,500	40,000
Trillion Btu---------------------	--	75	75	151	360
Percent of total sector inputs----	0	48.1	36.4	49.8	59.0
Total Sector Inputs:					
Trillion Btu---------------------	85.1	156	206	303	610
Percent of Region total sector inputs------------------	16.3	24.6	20.9	23.9	22.7
Total Region Sector Inputs:					
Trillion Btu---------------------	520.8	633	985	1,269	2,685

NOTE: Percentages may not add to 100 due to rounding.

Table 43 .--Northern Great Plains Region - Net Generation, Consumption, and Exports of Electricity, 1971 actual, and Projected to the year 2000

	1971	1975	1980	1985	2000
	(in trillion Btu)				
Net Generation:					
North Dakota----------------	28.2	23	72	93	296
South Dakota----------------	28.6	32	36	49	135
Montana---------------------	36.3	41	81	95	181
Wyoming---------------------	22.0	48	70	80	163
Nebraska--------------------	26.5	45	66	99	306
Region Total-------------	141.6	189	325	416	1,081
Consumption:					
North Dakota----------------	10.9	16	24	32	55
South Dakota----------------	11.0	14	21	26	45
Montana---------------------	34.6	44	62	79	142
Wyoming---------------------	12.5	19	31	48	93
Nebraska--------------------	33.9	42	59	81	134
Region Total-------------	102.9	135	197	266	469
Net Exports:					
North Dakota----------------	17.3	7	48	61	241
South Dakota----------------	17.6	18	15	23	90
Montana---------------------	1.7	-3	19	16	39
Wyoming---------------------	9.5	29	39	32	70
Nebraska--------------------	-7.4	3	7	18	172
Region Total-------------	38.7	54	128	150	612
	(in million Kwhr)				
Net Generation:					
North Dakota----------------	8,268	8,850	21,090	27,210	86,710
South Dakota----------------	8,391	9,210	10,560	14,340	39,400
Montana---------------------	10,653	11,730	23,720	27,810	52,750
Wyoming---------------------	6,458	13,970	20,530	23,367	47,860
Nebraska--------------------	7,766	13,300	19,300	29,000	90,000
Region Total-------------	41,536	57,060	95,200	121,727	316,720
Consumption:					
North Dakota----------------	3,188	4,689	7,034	9,378	16,120
South Dakota----------------	3,228	4,103	6,604	7,620	13,188
Montana---------------------	10,141	12,896	18,171	23,153	41,617
Wyoming---------------------	3,666	5,569	9,086	14,070	27,258
Nebraska--------------------	9,934	12,310	17,292	23,740	39,273
Region Total-------------	30,159	39,567	58,187	77,961	137,456
Net Exports:					
North Dakota----------------	5,080	4,161	14,056	17,832	70,590
South Dakota----------------	5,163	5,107	3,956	6,720	26,212
Montana---------------------	512	-1,166	5,549	4,657	11,133
Wyoming---------------------	2,792	8,401	11,444	9,297	20,602
Nebraska--------------------	-2,170	990	2,008	5,260	50,727
Region Total-------------	11,377	17,493	37,013	43,766	179,264

NOTE: Negative figures indicate consumption greater than productic

Appendix II-A

Table 44

Northern Great Plains Region - Net Exports of Energy Resources, 1971 Actual, and Projected to the Year 2000 - Intermediate Scenario

	1971	1975	1980	1985	2000
Coal:					
Million tons---------	10.3	34	66	84	110
Trillion Btu---------	276.5	499	978	1,249	1,636
Petroleum:					
Million barrels------	96.3	56	26	-11	-123
Trillion Btu---------	563.9	322	158	-32	-671
Natural Gas:					
Billion Cu. Ft.------	-36.9	-114	-191	-248	-413
Trillion Btu---------	-37.9	-117	-198	-255	-427
Synthetic Gas:					
Billion cu. ft.------	0	0	0	578	1,321
Trillion Btu---------	0	0	0	521	1,190
Utility Electricity:					
Million Kwhr---------	11,377	17,493	37,013	43,766	179,264
Trillion Btu---------	38.7	54	128	150	612
Total Trillion Btu-	841.2	758	1,066	1,633	2,340
Percent of U.S. Total Gross Energy Requirements	1.2	0.9	1.1	1.4	1.3

APPENDIX II-B.

ADDITIONAL ENERGY DATA AND SUPPLEMENTAL PAPERS

NORTHERN GREAT PLAINS REGION

APPENDIX II-B.

SECTION A. Tables from FPC, BUREAU OF POWER Staff Report on "Coal Burning Steam Electric Plants in Montana, Wyoming, North Dakota, and South Dakota, 1973-2000, Sept. 1973. Submitted to the National Energy Considerations Workgroup, Sept. 1973.

Tables from subsequent Staff Report on above subject for the State of Nebraska, submitted to the National Energy Considerations Workgroup, NGPRP, Oct. 1974

Clarification of proposed generating units in the Northern Great Plains Region, Bureau of Reclamation, Upper Missouri Region, November 1973.

ELECTRIC UTILITY INSTALLED GENERATING CAPACITY
NORTH DAKOTA
January 1, 1973

Owner or Operator	Plant Name	Location	Class of Ownership	MAXIMUM NAMEPLATE RATING - KW Hydro	Steam	Gas Turbines	Int. Comb. Engine	Fuel Used1/	Scheduled Retirements
Montana Dakota Utilities Co.	Beulah	Beulah	Private		13,300			Lignite	,000 KW - May 1981
"	Heskett	Mandan	"		100,000			Lignite, gas	
"	Williston	Williston	"		2,000	8,000		Oil, gas	2,000 KW (Steam - May 1981
"	Ellendale	Ellendale	"				3,400	Oil	
Northern States Power Co.	Bison	Minot	"		10,000			Lignite	November 1973
"	Minot	Minot	"				1,320	Oil	
"	Fargo	Fargo	"				2,760	Oil	
Otter Tail Power Co.	Devils Lake	Devils Lake	"		12,300			Lignite	May 1973
"	Jamestown	Jamestown	"		7,300			Lignite	May 1973
"	Kidder	Wahpeton	"		20,300			Lignite	May 1973
"	Bottineau	Bottineau	"				1,000	Oil	
"	Casselton	Casselton	"				1,000	Oil	
"	Cooperstown	Cooperstown	"				1,000	Oil	
"	Enderlin	Enderlin	"				400	Oil	
"	Langdon	Langdon	"				1,000	Oil	
"	Lisbon	Lisbon	"				400	Oil	
"	Oakes	Oakes	"				1,000	Oil	
"	Page	Page	"				600	Oil	
"	Parshall	Parshall	"				2,200	Oil	
"	Walhalla	Walhalla	"				600	Oil	
"	Westhope	Westhope	"				400	Oil	
Grafton Light & Power Dept.	Grafton	Grafton	Municipal				4,160	Oil	
Lakota Municipal	Lakota	Lakota	"				300	Oil	
Northwood Light & Power Co.	Northwood	Northwood	"				1,811	Oil	
Park River Light & Water	Park River	Park River	"				973	Oil	
Valley City Elec. & Wtr.	Valley City	Valley City	"		5,000			Lignite, Bit. coal	
"	Valley City	Valley City	"				2,729	Oil	
U. S. Army Engineers	Garrison	Riverdale	Federal	400,000					
Basin Elect. Pwr. Coop.	Leland Olds	Stanton	Cooperative		240,000			Lignite	
Central Power Elect. Coop.	William J. Neal	Velva	"		34,300			Lignite, oil	December 1973
Minnkota Power Coop. Inc.	R. M. Heskett	Grand Forks	"		81,500			Lignite, oil	
"	Milton R. Young	Center	"		234,550			Lignite, oil	
"	Grand Forks	Grand Forks	"				10,840	Oil	
"	Harwood	Harwood	"				4,800	Oil	
United Power Association	Stanton	Stanton	"		172,000			Lignite, oil	
TOTAL				400,000	873,350	8,000	43,084		

1/ Where multiple fuels are shown for steam plants, it does not necessarily imply that full capacity or continuous operation is possible with all fuels shown

ELECTRIC UTILITY INSTALLED GENERATING CAPACITY
SOUTH DAKOTA
January 1, 1973

Owner or Operator	Plant Name	Location	Class of Ownership	MAXIMUM NAMEPLATE RATING - KW Hydro	Steam	Gas Turbines	Int. Comb. Engines	Fuel Used[1]	Scheduled Retirements
Black Hills Pwr. & Lt. Co.	Falls	Hot Springs	Private	200					
"	Redwater	Spearfish	"	344					
"	Ben French	Rapid City	"		22,000			Bit. coal, oil, gas	
"	Ben French	Rapid City	"				10,000	Oil	
"	Kirk	Lead	"		31,500			Bit. coal	
"	Hot Springs	Hot Springs	"				800	Oil	
Don Jones	White River	White River	"	250					
Montana Dakota Utilities Co.	Mobridge	Mobridge	"		8,500			Lignite	May 1981
"	Mobridge	Mobridge	"				3,400	Oil	
Northern State Power Co	Lawrence	Sioux Falls	"		48,000			Bit. coal, oil, gas	
"	Pathfinder	Sioux Falls	"		75,000			Oil, gas	
"	Bridgewater	Bridgewater	"				1,840	Oil	
"	Salem	Salem	"				1,810	Oil, gas	
Northwestern Public Svc. Co.	Aberdeen	Aberdeen	"		12,500			Bit. coal, gas	5,000 KW-Nov. 1978; 7500 KW-Nov. 19
"	Huron	Huron	"			12,500		Oil, gas	
"	Mitchell	Mitchell	"		21,500			Bit. coal, gas	5,000 KW-Nov. 1978; 7500 KW-Nov. 1980
"	Armour	Armour	"				4,617	Oil	
"	Chamberlain	Chamberlain	"				7,215	Oil	
"	Clark	Clark	"				2,750	Oil, gas	
"	Faulkton	Faulkton	"				2,750	Oil	
"	Highmore	Highmore	"				2,035	Oil	
"	Redfield	Redfield	"				4,080	Oil, gas	
"	Webster	Webster	"				2,764	Oil	
"	Woonsocket	Woonsocket	"				1,340	Oil	
"	Yankton	Yankton	"				13,717	Oil, gas	3,281 KW - Oct. 1973
Otter Tail Power Co.	Britton	Britton	"				1,000	Oil	
"	Lake Preston	Lake Preston	"				1,000	Oil	
"	Sisseton	Sisseton	"				800	Oil	
"	Waubay	Waubay	"				600	Oil	
City of Beresford	Beresford	Beresford	Municipal				1,000	Oil	
Bryant Light & Power Dept.	Bryant	Bryant	"				314	Oil	
Elk Point Municipal Dept.	Elk Point	Elk Point	"				1,463	Oil	
Estelline Lt. & Pwr. Plant	Fairbanks	Estelline	"				613	Oil	
Faith Wtr. & Lt. Plant	Faith	Faith	"				700	Oil	
Flandreau Electric Plant	Flandreau	Flandreau	"				1,540	Oil	
Hecla Light & Power Plt.	Hecla	Hecla	"				230	Oil	
City of Howard	Howard	Howard	"				300	Oil	
Madison Lt. & Pwr Dept.	Madison	Madison	"				3,176	Oil	
Miller Lt. & Pwr. Plant	Miller	Miller	"				1,398	Oil	
Onida Lt. & Wtr. Works	Onida	Onida	"				500	Oil	
Parker Mun. Lt. Plant	Parker	Parker	"				800	Oil	
City of Pierre	Pierre	Pierre	"				5,320	Oil	
Pukwana Lt. & Pwr. Co.	Buckeye	Pukwana	"				100	Oil	
Sioux Falls Lt. & Pwr.	Sioux Falls	Sioux Falls	"				2,040	Oil	
Tyndall Lt. & Wtr. Plant	Tyndall	Tyndall	"				1,192	Oil	
Vermillion Lt. & Pwr. Plt.	Vermillion	Vermillion	"				7,[illegible]60	Oil, gas	
Volga City Mun. Dept.	Volga	Volga	"				[illegible]90	Oil	
City of Wessington Sprgs.	Wessington	Wessington Sprgs.	"				1,229	Oil	
U. S. Army Engineers	Oahe	Pierre	Federal	595,000					
"	Fort Randall	Pickstown	"	320,000					
"	Big Bend	Fort Thompson	"	468,000					
LaCreek Elec. Assn., Inc.	Martin	Martin	Cooperative				693	Oil	
Rosebud Elec. Coop., Inc.	Gregory	Gregory	"				870	Oil	
TOTAL				1,383,794	310,000	12,500	90,008		

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[1] Where multiple fuels are shown for steam plants, it does not necessarily imply that full capacity or continuous operation is possible with all fuels shown

ELECTRIC UTILITY INSTALLED GENERATING CAPACITY
MONTANA
January 1, 1973

Owner or Operator	Plant Name	Location	Class of Ownership	Hydro	Steam	Gas Turbines	Int. Comb. Engines	Fuel Used1/	
				MAXIMUM NAMEPLATE RATING - KW					
Montana Dakota Utilities Co.	Glendive	Glendive	Private		7,000			Oil, gas	Retire May 1981
"	Lewis & Clark	Sidney	"		50,000			Lignite, gas	
"	Baker	Baker	"				1,000	Gas	
"	Miles City	Miles City	"			23,267		Gas, oil	
Montana Light & Power Co.	Lake Creek	Troy	"	4,500					
"	Troy	Troy	"		3,000			Wood wastes	
"	Libby	Libby	"		12,550			Wood wastes	
Montana Power Company	Black Eagle	Great Falls	"	16,800					
"	Cochrane	Great Falls	"	48,000					
"	Flint Creek	Philipsburg	"	1,100					
"	Hauser Lake	Helena	"	17,000					
"	Holter	Wolf Creek	"	38,400					
"	Kerr	Polson	"	168,000					
"	Madison	Norris	"	9,000					
"	Milltown	Milltown	"	3,040					
"	Morony	Great Falls	"	45,000					
"	Mystic Lake	Columbus	"	10,000					
"	Rainbow	Great Falls	"	35,600					
"	Ryan	Great Falls	"	48,000					
"	Thompson Falls	Thompson Falls	"	30,000					
"	J.E. Corette	Billings	"		172,800			Bit. coal, gas	
"	Frank Bird	Billings	"		69,000			Oil, gas	
Pacific Power & Light Co.	Big Fork	Big Fork	"	4,150					
"	Libby	Libby	"			26,600		Oil	
Washington Wtr. Pwr. Co.	Noxon	Noxon	"	282,880					
U.S.B.R.	Hungry Horse	Hungry Horse	Federal	285,000					
"	Canyon Ferry	Canyon Ferry	"	50,000					
"	Yellowtail	Hardin	"	250,000					
U.S. Indian Irrigation Svc.	Big Creek	Polson	"	360					
U.S. Army Engineers	Fort Peck	Fort Peck	"	165,000					
TOTAL				1,511,830	314,350	49,867	1,000		

1/ Where multiple fuels are shown for steam plants, it does not necessarily imply that full capacity or continuous operation is possible with all fuels shown

ELECTRIC UTILITY INSTALLED GENERATING CAPACITY
WYOMING
January 1, 1973

Owner or Operator	Plant Name	Location	Class of Ownership	Hydro	Steam	Gas Turbines	Int. Comb. Engines	Fuel Used1/
				MAXIMUM NAMEPLATE RATING - KW				
Black Hills Pwr. & Lt. Co.	Osage	Osage	Private		34,500			Bit. coal, oil
"	Osage	Osage	"				1,000	Oil
"	Neil Simpson	Gillette	"		27,680			Bit. coal, oil
Cheyenne Lt., Fuel & Pwr. Co.	Snyder	Cheyenne	"				10,000	Oil
"	Corlett	Cheyenne	"				2,750	Oil
Montana Dakota Utilities Co.	Acme	Sheridan	"		8,000			Bit. coal
Pinedale Power & Light Co.	Pinedale	Pinedale	"	75				
Pacific Power & Light Co.	Dave Johnston	Glenrock	"		750,000			Bit. coal, oil, gas
"	Trona	Green River	"		15,625			Oil, gas
"	Lander	Lander	"				1,000	Oil
Utah Power & Light Co.	Naughton	Kemmerer	"		707,200			Bit. coal, oil, gas
Montana Power Co.	Lake Diesel	Yellowstone Park	"				1,750	Oil
"	Several small units in	Yellowstone Park	"	600			2,000	Oil
U. S. B. R.	Alcova	Alcova	Federal	36,000				
"	Fremont Canyon	Alcova	"	48,000				
"	Glendo	Glendo	"	24,000				
"	Guernsey	Guernsey	"	4,800				
"	Heart Mountain	Cody	"	5,000				
"	Kortes	Leo	"	36,000				
"	Pilot Butte	Morton	"	1,600				
"	Seminoe	Seminoe	"	32,400				
"	Shoshone	Cody	"	8,012				
"	Boysen	Shoshoni		15,000				
"	Fontenelle	Kemmerer	"	10,000				
Lower Valley Pwr. & Lt., Inc.	Swift Creek	Afton	Cooperative	800				
"	Strawberry	Bedford	"	1,500				Gas
University of Wyoming		Laramie	State		1,150			
TOTAL				221,787	1,544,155	-0-	18,500	

1/ Where multiple fuels are shown for steam plants, it does not necessarily imply that full capacity or continuous operation is possible with all fuels shown

ELECTRIC UTILITY INSTALLED GENERATING CAPACITY
NEBRASKA

January 1, 1973

Owner or Operator	Plant Name	Location (County)	Class of Ownership	Hydro	MAXIMUM NAMEPLATE RATING ----- KW			Nuclear	Fuel Used[1/]
					Steam	Gas Turbines	Int. Comb. Engines		
Alliance Municipal Utilities	Alliance	Box Butte	Municipal		16,500				Bituminous coal; natural gas
Alma Municipal Light Plant	Alma	Harlen	Municipal				4,493		Fuel oil; natural gas
Ansley Municipal Light Plant	Ansley	Custer	Municipal				1,365		Fuel oil
Auburn Board of Public Works	Plant #1	Nemaha	Municipal				7,603		Fuel oil; natural gas
Arnold Municipal Plant	Arnold	Custer	Municipal				1,180		Fuel oil
Beaver City Municipal Plant	Beaver City	Furnas	Municipal				2,200		Fuel oil; natural gas
Benkelman Lt. & Wtr. Dept.	Benkelman	Dandy	Municipal				1,050		Fuel oil
City of Blair	Blair	Washington	Municipal				14,190		Fuel oil; natural gas
Blue Hill Wtr. & Lt. Dept.	Blue Hill	Webster	Municipal				1,811		Fuel oil; natural gas
City of Broken Bow	Broken Bow	Custer	Municipal				8,718		Fuel oil; natural gas
Burwell Municipal Utility	Burwell	Garfield	Municipal				4,200		Fuel oil; natural gas
Cambridge Lt. & Wtr. Works	Cambridge	Furnas	Municipal				3,265		Fuel oil; natural gas
Campbell Municipal E. Dept.	Campbell	Franklin	Municipal				223		Fuel oil
City of Chappell	Chappell	Denel	Municipal				1,923		Fuel oil; natural gas
Crete Lt. & Water Works	Crete	Saline	Municipal				9,677		Fuel oil; natural gas
City of Curtis	Curtis	Frontier	Municipal				2,587		Fuel oil; natural gas
David City Lt. & Wtr. Dept.	David City	Butler	Municipal				5,750		Fuel oil; natural gas
Deshler Municipal Utilities	Deshler	Thayer	Municipal				1,570		Fuel oil; natural gas
Emerson Light & Pwr. Dept.	Emerson	Dixon	Municipal				1,990		Fuel oil; natural gas
Fairbury Lt. & Wtr. Dept.	Fairbury	Jefferson	Municipal		18,500				Fuel oil; natural gas
Falls City Wtr. & Lt. Dept.	Falls City	Richardson	Municipal				16,116		Fuel oil; natural gas
Franklin Elec. Light Plant	Franklin	Franklin	Municipal				2,325		Fuel oil; natural gas
Fremont Dept. of Utilities	Fremont	Dodge	Municipal		21,000				Bituminous coal; natural gas
Fremont Dept. of Utilities	Fremont 2	Dodge	Municipal		43,750				Bituminous coal; natural gas
Grand Island Elec. Dept.	C. W. Burdick	Hall	Municipal		92,500				Fuel oil; natural gas
Grand Island Elec. Dept.	Pine Street	Hall	Municipal		17,500				Fuel oil; natural gas
Hastings Utilities Dept.	North Denver	Adams	Municipal		50,500				Fuel oil; natural gas
Hastings Utilities Dept.	Don Henry	Adams	Municipal			22,000			Fuel oil; natural gas
Holbrook Lt. Pwr. & Ice Plant	Holbrook	Furnas	Municipal				408		Fuel oil
Holdrege Municipal Lt. & Wtr.	Holdrege	Phelps	Municipal				2,434		Fuel oil; natural gas
Grand Island Elec. Dept.	C. W. Burdick	Hall	Municipal			14,800			Fuel oil; natural gas

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[1/] Where multiple fuels are shown for steam plants, it does not necessarily imply that full capacity or continuous operation is possible with all fuels shown

ELECTRIC UTILITY INSTALLED GENERATING CAPACITY
NEBRASKA

January 1, 1973

Owner or Operator	Plant Name	Location (County)	Class of Ownership	MAXIMUM NAMEPLATE RATING -- K W Hydro	Steam	Gas Turbines	Internal Comb. Engines	Nuclear	Fuel Used[1/]
Imperial Light & Wtr. Plt.	Imperial	Chase	Municipal	120					
Imperial Light & Wtr. Plt.	Imperial	Chase	Municipal				756		Fuel oil
Kimball Municipal Utils.	Kimball	Kimball	Municipal				5,300		Fuel oil; natural gas
Laurel Municipal Pwr. Plt.	Laurel	Cedar	Municipal				2,523		Fuel oil; natural gas
Lincoln Electric System	Lincoln KS	Lancaster	Municipal		31,700				Bituminous coal; fuel oil; natural gas
Lincoln Electric System	Lincoln	Lancaster	Municipal			31,000			Fuel oil
Lodgepole Lt. & Wtr. Plt.	Lodgepole	Cheyenne	Municipal				245		Fuel oil
Lyons Light & Water Plt.	Lyons	Burt	Municipal				1,885		Fuel oil; natural gas
Madison Light Plant	Madison	Madison	Municipal				5,256		Fuel oil; natural gas
Municipal Light Plant	Callaway	Custer	Municipal				880		Fuel oil
Village of Mullen	Mullen	Hooker	Municipal				1,525		Fuel oil
Nebraska City Utilities	Nebraska City	Otoe	Municipal				11,200		Fuel oil; natural gas
Nebraska City Utilities	Syracuse	Otoe	Municipal				4,140		Fuel oil; natural gas
Ord Light & Water Plt.	Ord	Valley	Municipal				6,265		Fuel oil; natural gas
Oxford Light & Power Plt.	Oxford	Furnas	Municipal				4,165		Fuel oil; natural gas
Pender Municipal Lt. Plt.	Pender	Thurston	Municipal				5,330		Fuel oil; natural gas
City of Plainview	Plainview	Pierce	Municipal				1,805		Fuel oil; natural gas
Randolph Elec. Lt. & Wtr. Plt.	Randolph	Cedar	Municipal				2,865		Fuel oil; natural gas
Red Cloud Light & Power Plt.	Red Cloud	Webster	Municipal				3,098		Fuel oil; natural gas
City of Sargent	Sargent	Custer	Municipal				2,643		Fuel oil; natural gas
Schuyler Department of Util.	Schuyler	Colfax	Municipal		8,000				Fuel oil; natural gas
City of Sidney	Sidney	Cheyenne	Municipal				8,642		Fuel oil; natural gas
Spalding Mun. Lt. Pwr. Plt.	Spalding	Greeley	Municipal	140					
Spalding Mun. Lt. Pwr. Plt.	Spalding	Greeley	Municipal				788		Fuel oil
Stratton Ice Lt. & Wtr. Syst.	Stratton	Hitchcock	Municipal				755		Fuel oil
Stuart Light & Power Plt.	Stuart	Holt	Municipal				442		Fuel oil
Sutherland Lt. & Pwr. Plt.	Sutherland	Lincoln	Municipal				2,934		Fuel oil; natural gas
Tecumseh Lt. & Wtr. Dept.	Tecumseh	Johnson	Municipal				5,308		Fuel oil; natural gas
Trenton Lt. & Pwr. Plant	Trenton	Hitchcock	Municipal				880		Fuel oil
Wahoo Water & Light Dept.	Wahoo	Saunders	Municipal				10,490		Fuel oil; natural gas
Wakefield Light Plant	Wakefield	Dixon	Municipal				4,870		Fuel oil; natural gas

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ELECTRIC UTILITY INSTALLED GENERATING CAPACITY
NEBRASKA

January 1, 1973

Owner or Operator	Plant Name	Location (County)	Class of Ownership	MAXIMUM NAMEPLATE RATING ----KW Hydro	Steam	Gas Turbines	Int. Comb. Engines	Nuclear	Fuel Used[1/]
Wayne Light Department	Wayne	Wayne	Municipal				13,825		Fuel oil; natural gas
West Point Lt. & Wtr. Wks.	West Point	Cuming	Municipal				9,065		Fuel oil; natural gas
Wauneta Municipal Utl.	Wauneta	Chase	Municipal				617		Fuel oil
Wilber Light & Power	Wilber	Saline	Municipal				2,430		Fuel oil; natural gas
Wisner Elec. Lt. & Wtr. Plt.	Wisner	Cuming	Municipal				1,905		Fuel oil; natural gas
Corps of Engineers	Gavins Point	Knox	Federal Project	100,035					
Cent. Neb. Pub. Pwr. & Irr. Dis.	Jeffrey Cyn	Lincoln	Power District	18,000					
Cent. Neb. Pub. Pwr. & Irr. Dis.	Johnson 1	Gosper	Power District	18,000					
Cent. Neb. Pub. Pwr. & Irr. Dis.	Johnson 2	Gosper	Power District	18,000					
Cent. Neb. Pub. Pwr. & Irr. Dis.	Canaday	Gosper	Power District		100,000				Fuel oil; natural gas
Cent. Neb. Pub. Pwr. District	Blue Spgs 2	Gage	Power District	418					
Cent. Neb. Pub. Pwr. District	Columbus	Platte	Power District	39,900					
Cent. Neb. Pub. Pwr. District	Ericson	Wheeler	Power District	330					
Cent. Neb. Pub. Pwr. District	Ft. Niobrara	Cherry	Power District	980					
Cent. Neb. Pub. Pwr. District	Gothenburg	Dawson	Power District	400					
Cent. Neb. Pub. Pwr. District	Holmesville	Gage	Power District	280					
Cent. Neb. Pub. Pwr. District	Kearney	Buffalo	Power District	1,500					
Cent. Neb. Pub. Pwr. District	Minnechaduza	Cherry	Power District	200					
Cent. Neb. Pub. Pwr. District	Monroe	Platte	Power District	7,838					
Cent. Neb. Pub. Pwr. District	No Platte	Lincoln	Power District	26,100					
Cent. Neb. Pub. Pwr. District	Spencer	Boyd	Power District	2,640					
Cent. Neb. Pub. Pwr. District	Kramer	Sarpy	Power District		112,500				Bituminous coal; natural gas
Cent. Neb. Pub. Pwr. District	Ogallala	Keith	Power District		7,500				Fuel oil; natural gas
Cent. Neb. Pub. Pwr. District	Scottsblf N	Scottsbluff	Power District		42,400				Fuel oil; natural gas
Cent. Neb. Pub. Pwr. District	Sheldon	Lancaster	Power District		231,800				Bituminous coal; natural gas
Cent. Neb. Pub. Pwr. District	Chadron	Dawes	Power District				2,500		Fuel oil
Cent. Neb. Pub. Pwr. District	Gordon No. 1	Sheridan	Power District				2,000		Fuel oil
Cent. Neb. Pub. Pwr. District	Ogallala	Keith	Power District				3,685		Fuel oil
Cent. Neb. Pub. Pwr. District	Valentine	Cherry	Power District				1,668		Fuel oil

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ELECTRIC UTILITY INSTALLED GENERATING CAPACITY
NEBRASKA

January 1, 1973

Owner or Operator	Plant Name	Location (County)	Class of Ownership	MAXIMUM NAMEPLATE RATING ----K W Hydro	Steam	Gas Turbines	Int. Comb. Engines	Nuclear	Fuel Used[1/]
Norris Rural Pub. Pwr. Dist.	Barneston	Gage	Power District	720					
Omaha Pub. Pwr. District	Jones St.	Douglas	Power District		173,500				Bituminous coal; fuel oil; natural gas
Omaha Pub. Pwr. District	North Omaha	Douglas	Power District		644,700				Bituminous coal; natural gas
Omaha Pub. Pwr. District	South Omaha	Douglas	Power District		20,000				Fuel oil; natural gas
Omaha Pub. Pwr. District	Sarpy City	Sarpy	Power District			108,000			Fuel oil; natural gas
Southwest Pub. Pwr. Dist.	Palisade	Hitchcock	Power District				312		Fuel oil
TOTALS				235,621	1,632,330	175,800	228,075	-0-	

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1/ Where multiple fuels are shown for steam plants, it does not necessarily imply that full capacity or continuous operation is possible with all fuels shown

PROJECTED ADDITIONS OF ELECTRIC GENERATION CAPACITY
1973 - 1982
REGIONAL RELIABILITY COUNCIL REPORTS TO THE FEDERAL POWER COMMISSION DATED APRIL 1, 1973
MONTANA - WYOMING - NORTH DAKOTA - SOUTH DAKOTA

Owner or Operator	Plant Name	Location	Class of Ownership	CAPACITY - KW Hydro	Steam	Gas Turbines	Int. Comb. Engines	Fuel	Scheduled Operation
Montana Pwr. Co.-Puget Sound	Colstrip #1	Colstrip, Montana	Private		330,000			Coal	July 1975
Montana Power Company	Colstrip #2	" "	"		330,000			Coal	July 1976
Montana Pwr. Co. and Others	Colstrip #3	" "	"		700,000			Coal	July 1978
Montana Pwr. Co. and Others	Colstrip #4	" "	"		700,000			Coal	July 1979
U. S. Army Engineers	Libby #1	Libby, Montana	Federal	121,000					July 1975
U. S. Army Engineers	Libby #2	" "	"	121,000					Oct. 1975
U. S. Army Engineers	Libby #3	" "	"	121,000					Jan. 1976
U. S. Army Engineers	Libby #4	" "	"	121,000					April 1976
U. S. Army Engineers	Libby #5	" "	"	121,000					Oct. 1983
Idaho Power Company	J. Bridger #1	Rock Springs, Wyo.	Private		300,000			Coal	June 1974
Pacific Power & Light Co.	J. Bridger #2	" "	"		500,000			Coal	Sept. 1975
Pacific Power & Light Co.	J. Bridger #3	" "	"		300,000			Coal	Sept. 1976
Pacific Pwr. & Lt. w/others	Wyodak	Gillette, Wyoming	"		330,000			Coal	May 1977
Basin Elec. Power Coop.	L. Olds #2	Stanton, N. Dak.	Cooperative		438,000			Lignite	Oct. 1975
Minnkota Power Coop.	Center #2	Center, N. Dak.	"		435,000			Lignite	May 1977
Cooperative Pwr. Assn.-Others	Lignite #1	North Dakota	"		400,000			Lignite	Nov. 1978
Cooperative Pwr. Assn.-Others	Lignite #2	North Dakota	"		400,000			Lignite	Nov. 1979
Basin Elec. Power Coop	1979 Prop.	North Dakota	"		360,000			Lignite	May 1979
Montana-Dakota Utilities	1980 Prop.	North Dakota	Private			10,000		Oil, gas	May 1980
Montana-Dakota Utilities	1981 Prop.	North Dakota	"		300,000			Lignite	May 1981
Northern States Power Co.	1981 Prop.	North Dakota	"		800,000			Lignite	May 1981
Otter Tail Power Company	1981 Prop.	North Dakota	"		800,000			Lignite	May 1981
Otter Tail Power. w/Others	Big Stone	Big Stone Lake, S. Dak.	"		430,000			Lignite from N. Dak.	May 1975
Northwestern Pub. Svc. Co.	Yankton #4	Yankton, South Dakota	"				4,000	Oil	Jan. 1976
Northwestern Pub. Svc. Co.	Aberdeen	Aberdeen, South Dakota	"			20,000		Oil, gas	May 1978
Northwestern Pub. Svc. Co.	Mitchell	Mitchell, South Dakota	"			20,000		Oil, gas	May 1979
Northwestern Pub. Svc. Co.	Proposed	South Dakota	"			20,000		Oil, gas	May 1980
Northwestern Pub. Svc. Co.	Proposed	South Dakota	"		300,000			Coal	May 1981
TOTAL				605,000	7,193,000	60,000	4,000		

PROJECTED ADDITIONS OF ELECTRIC GENERATING CAPACITY
1973 - 1982
As Reported In
REGIONAL RELIABILITY COUNCIL REPORTS TO THE FEDERAL POWER COMMISSION DATED APRIL 1, 1973

NEBRASKA

Owner or Operator	Plant Name	Location	Class of Ownership	CAPACITY - - - - KW					Fuel	Scheduled Operation
				Hydro	Steam	Gas Turbines	Int. Comb. Engines	Nuclear		
Nebraska Public Pwr. Dist.	Sheldon	Hallam	Public			49,700			Oil, gas	April 1, 1973
Nebraska Public Pwr. Dist.	McCook	McCook	Public			47,700			Oil, gas	April 1, 1973
Nebraska Public Pwr. Dist.	Hebron	Hebron	Public			49,700			Oil, gas	April 1, 1973
Nebraska Public Pwr. Dist.	Cooper	Brownville	Public					778,000		Nov. 1, 1973
Nebraska Public Pwr. Dist.	Cooper	Brownville	Public					32,000		Nov. 1, 1974 (uprate)
Nebraska Public Pwr. Dist.	Gentleman	Sutherland	Public		600,000				Coal (Wyo.)	Nov. 1, 1977
Omaha Public Pwr. Dist.	Omaha G. T.	Omaha	Public			116,000			Oil, gas	May 1, 1973
Omaha Public Pwr. Dist.	Ft. Calhoun	Ft. Calhoun	Public					455,000		Oct. 1973
Omaha Public Pwr. Dist.	Ft. Calhoun	Ft. Calhoun	Public					20,000		Oct. 1975 (uprate)
Omaha Public Pwr. Dist.	Omaha G. T.	Omaha	Public			120,000			Oil, gas	May 1, 1978
Omaha Public Pwr. Dist.	Ft. Calhoun	Ft. Calhoun	Public					900,000		May 1981
Fairbury Lt. & Wtr. Dept.	Fairbury	Fairburn	Municipal				6,000			June 1976
Fremont Dept. of Utilities	Plant #2	Fremont	Municipal		85,000					January 1976
Hastings Utilities	Hastings #7	Hastings	Municipal		75,000					June 1977
Nebraska City Utilities		Nebraska City	Municipal				6,000			1974
Nebraska City Utilities		Nebraska City	Municipal				2,000			1976
Nebraska City Utilities		Nebraska City	Municipal				2,000			1977
Nebraska City Utilities		Nebraska City	Municipal				6,000			1978
Nebraska City Utilities		Nebraska City	Municipal				2,000			1981
Nebraska City Utilities		Nebraska City	Municipal				2,000			1982

ELECTRIC UTILITY INSTALLED GENERATING CAPACITY AND NET GENERATION BY FUEL TYPE
NORTH DAKOTA
1960 - 1972 Actual
1973 - 2000 Projected1/

Year	INSTALLED CAPACITY-MAXIMUM NAMEPLATE RATING - KW						NET GENERATION - 1000 kWh						
	Hydro	Steam	Nuclear	Gas Turbines	Int. Comb. Engines	Total	Bit. Coal	Lignite	Oil	Gas	Hydro	Nuclear	Total
1960	400,000	216,790		8,000	40,888	665,678		708,165	7,766	4,061	1,060,106		[illegible]
1961	400,000	216,790		8,000	40,847	665,637		807,690	7,687	600	1,406,721		[illegible]
1962	400,000	213,790		8,000	43,673	665,463		799,350	5,937	15,954	1,292,911		2,114,152
1963	400,000	286,290		8,000	43,672	737,962		701,658	4,072	1,451	1,483,191		2,190,372
1964	400,000	295,290		8,000	43,672	746,962		850,007	1,386	97	1,877,867		2,729,367
1965	400,000	290,800		8,000	43,348	740,148		750,872	900	189	2,497,393		3,248,936
1966	400,000	508,800		8,000	42,968	959,768		1,694,586	66	138	1,928,804		3,623,632
1967	400,000	666,000		8,000	42,968	1,116,968		2,577,202	7,006	193	2,770,761		5,355,160
1968	400,000	666,000		8,000	42,968	1,116,968		3,166,576	13,257	703	2,479,394		5,659,930
1969	400,000	658,000		8,000	42,059	1,108,059		3,182,229	5,431	3,349	2,938,920		6,129,929
1970	400,000	892,350		8,000	43,059	1,343,409		3,817,489	13,421	18,236	2,814,508		6,663,764
1971	400,000	856,550		8,000	43,059	1,307,609		4,917,815	96,389	19,048	3,235,311		8,268,563
1972	400,000	873,550		8,000	43,086	1,324,636		5,460,619	17,625	16,360	3,086,856		8,509,470
1973	400,000	829,050		8,000	43,086	1,280,136		5,400,000	20,000	10,000	3,000,000		8,430,000
1974	400,000	829,050		8,000	43,086	1,280,136		5,400,000	20,000	10,000	3,000,000		8,430,000
1975	400,000	1,226,550		8,000	43,086	1,677,636		5,800,000	40,000	10,000	3,000,000		8,850,000
1976	400,000	1,226,550		8,000	43,086	1,677,636		7,700,000	140,000	10,000	3,000,000		10,850,000
1977	400,000	1,661,550		8,000	43,086	2,112,636		8,900,000	200,000	10,000	3,000,000		12,110,000
1978	400,000	2,061,550		8,000	43,086	2,512,636		10,200,000	250,000	10,000	3,000,000		13,460,000
1979	400,000	2,961,550		8,000	43,086	3,412,636		14,000,000	420,000	10,000	3,000,000		17,430,000
1980	400,000	2,961,550		28,000	43,086	3,432,636		17,300,000	780,000	10,000	3,000,000		21,090,000
1981	400,000	4,053,550		28,000	43,086	4,524,636		20,000,000	970,000	10,000	3,000,000		23,980,000
1982	400,000	4,053,550		28,000	43,086	4,524,636		23,000,000	1,200,000	10,000	3,000,000		27,210,000
1985	400,000	4,053,550		28,000	43,086	4,524,636		23,000,000	1,200,000	10,000	3,000,000		27,210,000
1990	400,000	6,400,000		50,000	30,000	6,880,000		35,000,000	1,800,000	10,000	3,000,000		39,810,000
1995	400,000	9,800,000		70,000	30,000	10,300,000		53,000,000	1,700,000	10,000	3,000,000		58,710,000
2000	400,000	14,800,000		90,000	20,000	15,310,000		80,000,000	3,700,000	10,000	3,000,000		86,710,000

1/ Capacity additions for the 1973-1982 period taken from Regional Council reports to Federal Power Commission dated April 1, 1973

ELECTRIC UTILITY INSTALLED GENERATING CAPACITY AND NET GENERATION BY FUEL TYPE
SOUTH DAKOTA
1960 - 1972 Actual
1973 - 2000 Projected2/

Year	INSTALLED CAPACITY-MAXIMUM NAMEPLATE RATING - KW						NET GENERATION - 1000 kWh						
	Hydro	Steam	Nuclear	Gas Turbines	Int. Comb. Engines	Total	Bit. Coal	Lignite	Oil	Gas	Hydro	Nuclear	Total
1960	326,496	156,750			60,957	545,203	245,688	16,361	22,747	281,759	1,135,857		1,699,908
1961	332,996	169,250		13,000	60,182	575,428	239,383	15,161	23,716	309,586	1,126,228		1,716,050
1962	662,996	169,250		15,000	71,697	918,943	278,929	6,878	38,186	370,876	1,480,016		2,174,877
1963	917,996	169,250		15,000	70,962	1,173,088	283,162	3,936	22,968	277,344	2,879,217		3,466,599
1964	1,036,996	172,250		15,000	70,502	1,292,748	261,552	(297)	16,738	262,749	3,062,499		3,601,201
1965	1,210,496	172,250		12,500	70,406	1,473,650	277,668	(382)	19,366	203,560	3,834,787		4,335,029
1966	1,386,996	167,250	66,000	12,500	75,215	1,705,959	242,799	(1,330)	19,546	206,510	4,814,731	9,017	5,291,273
1967	1,383,796	232,250		12,500	80,123	1,708,669	287,084	(445)	16,939	213,916	4,895,812	66,665	5,479,969
1968	1,383,796	163,750		12,500	80,040	1,640,086	283,149	849	16,869	225,286	5,613,735	(2,688)	6,137,176
1969	1,383,796	238,750		12,500	81,610	1,716,656	300,642	5,476	42,147	213,357	6,317,898		6,879,518
1970	1,383,796	230,750		12,500	80,886	1,707,932	318,151	16,191	136,979	201,367	6,563,668		7,306,316
1971	1,383,796	230,750		12,500	89,136	1,716,182	331,300	7,796	94,262	215,905	7,741,427		8,390,690
1972	1,383,796	225,500 1/		12,500	90,008	1,711,804	321,972	1,687	162,383	239,256	7,389,912		8,095,205
1973	1,383,796	225,500		12,500	90,008	1,711,804	340,000	20,000	180,000	200,000	7,300,000		8,040,000
1974	1,383,796	225,500		12,500	96,008	1,717,804	340,000	20,000	180,000	200,000	7,300,000		8,040,000
1975	1,383,796	655,500		12,500	96,008	2,147,804	340,000	1,140,000	230,000	200,000	7,300,000		9,210,000
1976	1,383,796	655,500		12,500	96,008	2,147,804	340,000	2,300,000	300,000	200,000	7,300,000		10,440,000
1977	1,383,796	655,500		12,500	96,008	2,147,804	340,000	2,300,000	300,000	200,000	7,300,000		10,440,000
1978	1,383,796	645,500		32,500	96,008	2,157,804	340,000	2,300,000	340,000	200,000	7,300,000		10,480,000
1979	1,383,796	665,500		32,500	96,008	2,177,804	340,000	2,300,000	380,000	200,000	7,300,000		10,520,000
1980	1,383,796	630,500		72,500	90,727	2,177,323	340,000	2,300,000	420,000	200,000	7,300,000		10,560,000
1981	1,383,796	722,000		72,500	90,727	2,269,023	340,000	2,550,000	430,000	200,000	7,300,000		10,820,000
1982	1,383,796	722,000		72,500	90,727	2,269,023	340,000	2,830,000	450,000	200,000	7,300,000		11,120,000
1985	1,383,796	1,322,000		92,500	80,000	2,868,296	340,000	5,900,000	600,000	200,000	7,300,000		14,340,000
1990	1,383,796	2,322,000		132,000	70,000	3,907,796	340,000	11,000,000	1,200,000	200,000	7,300,000		20,040,000
1995	1,383,796	3,822,000		152,000	70,000	5,427,796	340,000	18,500,000	1,700,000	200,000	7,300,000		28,040,000
2000	1,383,796	5,800,000		200,000	60,000	7,443,796	300,000	29,000,000	2,700,000	200,000	7,300,000		39,600,000

1/ Includes 15,500 kW retired 12-31-72

2/ Capacity additions for the 1973-1982 period taken from Regional Council reports to Federal Power Commission dated April 1, 1973

ELECTRIC UTILITY INSTALLED GENERATING CAPACITY AND NET GENERATION BY FUEL TYPE
MONTANA
1960 - 1972 Actual
1973 - 2000 Projected1/

Year	INSTALLED CAPACITY-MAXIMUM NAMEPLATE RATING - KW Hydro	Steam	Nuclear	Gas Turbines	Int. Comb. Engines	Total	NET GENERATION - 1000 kWh Bit. Coal	Lignite	Oil	Gas	Hydro	Wood-Waste	Total
1960	1,234,990	115,000			2,442	1,353,192		182,205	23	8,917	5,800,896		5,991,861
1961	1,314,990	113,600			1,736	1,430,276		262,539	6	18,799	6,498,418		6,779,763
1962	1,261,830	113,600			1,726	1,377,156		290,636	635	349,862	6,410,087		7,051,250
1963	1,261,830	134,250			1,000	1,397,080		284,383	321	298,398	6,011,365		6,596,467
1964	1,261,830	133,650			1,000	1,396,480		284,615	1,735	219,708	6,820,306	91,423	7,354,785
1965	1,261,830	133,650			1,000	1,396,480		205,061	347	170,779	8,309,202	36,586	8,001,953
1966	1,511,830	143,550			1,000	1,656,380		316,763	63,241	272,701	7,939,963	38,613	8,611,280
1967	1,511,830	143,550			1,000	1,656,380		314,125	3,046	41,209	8,704,980	56,093	9,119,433
1968	1,511,830	316,350			1,000	1,829,180	124,686	309,150	9,657	52,449	8,925,401	73,995	9,495,348
1969	1,511,830	316,350			1,000	1,829,180	623,253	311,573	52,361	166,079	9,448,896	60,666	10,663,566
1970	1,511,830	316,350			1,000	1,829,180	631,368	334,982	13,620	220,476	8,764,817	72,336	10,025,803
1971	1,511,830	316,350			1,000	1,829,180	564,039	337,335	40	96,286	9,594,333	60,629	10,652,662
1972	1,511,830	314,350		49,867	1,000	1,877,047	769,225	329,432	7,438	100,470	9,464,468	51,229	10,690,282
1973	1,511,830	314,350		49,867	1,000	1,877,047	800,000	340,000	50,000	100,000	9,400,000	50,000	10,740,000
1974	1,511,830	314,350		49,867	1,000	1,877,047	800,000	340,000	50,000	100,000	9,400,000	50,000	10,740,000
1975	1,753,830	644,350		49,867	1,000	2,449,047	1,600,000	340,000	100,000	100,000	9,540,000	50,000	11,730,000
1976	1,995,830	974,350		49,867	1,000	3,021,047	3,200,000	340,000	300,000	100,000	10,200,000	50,000	14,190,000
1977	1,995,830	974,350		49,867	1,000	3,021,047	3,200,000	340,000	300,000	100,000	10,200,000	50,000	14,190,000
1978	1,995,830	1,674,350		49,867	1,000	3,721,047	5,000,000	340,000	390,000	100,000	10,200,000	50,000	16,080,000
1979	1,995,830	2,374,350		49,867	1,000	4,421,047	10,500,000	340,000	640,000	100,000	10,200,000	50,000	21,830,000
1980	1,995,830	2,374,350		49,867	1,000	4,421,047	12,300,000	340,000	730,000	100,000	10,200,000	50,000	23,720,000
1981	1,995,830	2,567,350		49,867	1,000	4,614,047	12,300,000	340,000	730,000	100,000	10,200,000	50,000	23,720,000
1982	2,116,830	2,567,350		49,867	1,000	4,735,047	12,300,000	340,000	730,000	100,000	10,235,000	50,000	23,755,000
1985	2,117,000	3,000,000		100,000	1,000	5,218,000	20,300,000	6,000,000	960,000	100,000	10,400,000	50,000	37,810,000
1990	2,117,000	4,400,000		100,000	1,000	6,618,000	19,700,000	6,000,000	1,300,000	100,000	10,400,000	50,000	37,550,000
1995	2,117,000	5,800,000		150,000	1,000	8,068,000	23,000,000	7,700,000	1,700,000	100,000	10,400,000	50,000	42,950,000
2000	2,117,000	7,900,000		200,000	1,000	11,217,000	30,000,000	11,000,000	1,200,000	100,000	10,400,000	50,000	52,750,000

1/ Capacity additions for the 1973-1982 period taken from Regional Council reports to Federal Power Commission dated April 1, 1973

ELECTRIC UTILITY INSTALLED GENERATING CAPACITY AND NET GENERATION BY FUEL TYPE
WYOMING
1960 - 1972 Actual
1973 - 2000 Projected1/

Year	INSTALLED CAPACITY-MAXIMUM NAMEPLATE RATING - KW Hydro	Steam	Nuclear	Gas Turbines	Int. Comb. Engines	Total	NET GENERATION - 1000 kWh Bit. Coal	Lignite	Oil	Gas	Hydro	Nuclear	Total
1960	188,430	176,860			15,653	381,963	936,883		4,968	37,009	608,908		1,587,756
1961	213,430	301,360			15,022	529,812	1,292,337		8,380	32,636	632,545		1,965,898
1962	212,490	296,560			17,367	526,717	1,275,061		2,008	35,017	975,365		2,288,221
1963	212,560	449,460			21,440	683,460	2,267,466		9,879	9,579	878,720		3,165,644
1964	212,560	663,750			23,440	899,750	2,467,397		6,200	4,755	874,305		3,352,665
1965	212,140	632,250			21,117	865,507	2,666,673		16,655	4,316	886,247		3,573,891
1966	212,140	632,250			20,567	864,957	3,381,073		7,289	3,861	992,533		4,384,756
1967	212,140	632,250			23,317	867,707	3,206,736		8,900	2,610	708,826		3,927,072
1968	222,552	876,075			23,317	1,121,944	3,672,981		15,306	7,035	959,373		4,654,695
1969	222,552	892,575			19,157	1,134,284	4,733,239		13,969	68,261	1,096,990		5,912,459
1970	222,552	892,575			19,157	1,134,284	5,426,658		12,493	61,563	1,006,413		6,507,127
1971	221,952	1,218,975			19,157	1,460,084	5,805,381		26,572	115,827	1,312,115		7,259,895
1972	221,787	1,544,155			19,500	1,785,442	6,976,956		22,822	64,271	1,172,300		8,236,349
1973	221,787	1,544,155			19,500	1,785,442	8,313,000		500,000	60,000	1,200,000		10,073,000
1974	221,787	2,044,155			19,500	2,285,442	9,613,000		1,060,000	60,000	1,200,000		11,933,000
1975	221,787	2,544,155			19,500	2,785,442	11,560,000		1,150,000	60,000	1,200,000		13,970,000
1976	221,787	3,044,155			19,500	3,285,442	14,160,000		1,270,000	60,000	1,200,000		16,690,000
1977	221,787	3,374,155			19,500	3,615,442	16,770,000		1,390,000	60,000	1,200,000		19,420,000
1978	221,787	3,374,155			19,500	3,615,442	17,830,000		1,440,000	60,000	1,200,000		20,530,000
1979	221,787	3,374,155			19,500	3,615,442	17,830,000		1,440,000	60,000	1,200,000		20,530,000
1980	221,787	3,374,155			19,500	3,615,442	17,830,000		1,440,000	60,000	1,200,000		20,530,000
1981	221,787	3,374,155			19,500	3,615,442	17,830,000		1,440,000	60,000	1,200,000		20,530,000
1982	221,787	3,374,155			19,500	3,615,442	17,830,000		1,440,000	60,000	1,200,000		20,530,000
1985	221,787	3,374,155			19,500	3,615,442	17,830,000		1,440,000	60,000	1,200,000		20,530,000
1990	221,787	4,600,000		20,000	17,000	4,858,787	24,200,000		1,800,000	60,000	1,200,000		27,260,000
1995	221,787	6,200,000		20,000	17,000	6,458,787	32,500,000		2,200,000	60,000	1,200,000		35,960,000
2000	221,787	8,400,000		40,000	15,000	8,676,787	43,800,000		2,600,000	60,000	1,200,000		47,660,000

1/ Capacity additions for the 1973-1982 period taken from Regional Council reports to Federal Power Commission dated April 1, 1973

ELECTRIC UTILITY INSTALLED GENERATING CAPACITY AND NET GENERATION BY FUEL TYPE
NEBRASKA
1960 - 1972 Actual
1973 - 2000 Projected[1]

Year	INSTALLED CAPACITY - MAXIMUM NAMEPLATE RATING ----- KW						NET GENERATION-------------------------1000 kWh						
	Hydro	Steam	Nuclear	Gas Turbines	Int. Comb. Engines	Total	Bit. Coal	Wood or Waste	Oil	Gas	Hydro	Nuclear	Total
1960	240,032	843,150			141,140	1,224,322	601,593	48,472	81,100	2,661,809	958,510		4,351,484
1961	239,872	950,650			147,743	1,338,265	472,068	48,772	82,672	2,898,776	927,719		4,430,007
1962	239,010	956,150			149,594	1,344,754	855,898	36,629	109,529	2,801,757	974,924		4,778,737
1963	238,025	1,195,950			152,786	1,586,761	1,025,369	40,676	123,795	3,144,991	1,013,238	74,575	5,422,644
1964	238,025	1,193,950			156,346	1,588,321	1,136,817	29,164	72,549	3,184,417	1,002,191	90,807	5,515,945
1965	238,025	1,191,700			159,917	1,589,642	1,110,973		68,628	3,113,485	1,115,416	(5,440)	5,403,060
1966	237,621	1,243,100			164,744	1,645,465	931,774		64,036	3,467,161	1,162,172		5,625,143
1967	237,621	1,243,100			171,744	1,652,465	1,148,366		55,495	3,449,877	1,162,850		5,816,588
1968	237,621	1,590,750			175,607	2,003,978	1,234,269		66,076	4,231,303	1,253,976		6,785,624
1969	237,621	1,590,750			181,777	2,010,148	2,077,588		91,813	3,960,257	1,237,442		7,367,100
1970	237,621	1,590,750			188,396	2,016,767	2,291,630		150,997	4,157,602	1,370,320		7,970,549
1971	237,621	1,581,850			195,796	2,015,267	2,064,608		99,478	4,241,309	1,359,171		7,764,566
1972	235,621	1,632,350		175,800	228,075	2,271,846	2,649,558		198,773	4,213,969	1,371,883		8,434,133
1973	235,621	1,632,350		438,900	228,075	2,534,946	3,000,000		1,000,000	4,000,000	1,300,000		9,300,000
1974	235,621	1,632,350	1,233,000	438,900	234,075	3,773,946	2,000,000		1,000,000	4,000,000	1,300,000	4,100,000	12,400,000
1975	235,621	1,536,350	1,265,000	438,900	234,075	3,709,946	2,000,000		1,000,000	4,000,000	1,300,000	5,000,000	13,300,000
1976	235,621	1,508,350	1,285,000	438,900	242,075	3,709,946	2,000,000		1,000,000	4,000,000	1,300,000	7,000,000	14,300,000
1977	235,621	1,508,350	1,285,000	438,900	244,075	3,711,946	2,100,000		1,000,000	4,000,000	1,300,000	7,000,000	15,400,000
1978	235,621	2,183,350	1,285,000	558,900	250,075	4,512,946	2,700,000		1,600,000	4,000,000	1,300,000	7,000,000	16,600,000
1979	235,621	2,183,350	1,285,000	558,900	250,000	4,512,871	4,000,000		1,600,000	4,000,000	1,300,000	7,000,000	17,900,000
1980	235,621	2,165,350	1,285,000	558,900	250,000	4,494,871	5,400,000		1,600,000	4,000,000	1,300,000	7,000,000	19,300,000
1981	235,621	2,165,350	1,285,000	558,900	252,000	4,496,871	6,900,000		1,600,000	4,000,000	1,300,000	7,000,000	20,800,000
1982	235,621	2,165,350	2,185,000	558,900	254,000	5,398,871	3,900,000		1,600,000	4,000,000	1,300,000	11,600,000	22,400,000
1985	236,000	3,014,000	2,700,000	600,000	230,000	6,800,000	7,500,000		1,700,000	4,000,000	1,300,000	14,500,000	29,000,000
1990	236,000	4,064,000	3,600,000	800,000	200,000	8,900,000	15,700,000		2,000,000	4,000,000	1,300,000	19,000,000	42,000,000
1995	236,000	5,514,000	4,600,000	1,000,000	150,000	11,500,000	28,200,000		2,500,000	4,000,000	1,300,000	25,000,000	61,000,000
2000	236,000	6,664,000	6,600,000	1,500,000	100,000	15,100,000	40,700,000		4,000,000	4,000,000	1,300,000	40,000,000	90,000,000

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[1] Capacity additions for the 1973-1982 period taken from Regional Council reports to FPC dated April 1, 1973

ELECTRIC UTILITY FOSSIL FUEL CONSUMPTION IN ELECTRIC GENERATING PLANTS
1960-1972 Actual
1973-2000 Projected

NORTH DAKOTA

Year	FOSSIL FUEL CONSUMED			Gas Mcf
	Bit. Coal Short Tons	Lignite Short Tons	Oil 42 Gal. Bbls	
1960		1,013,897	19,527	102,778
1961		1,130,374	19,386	32,603
1962		1,101,692	16,315	276,466
1963		955,565	10,700	30,138
1964		1,065,337	4,432	20,616
1965		963,569	[illegible],929	25,451
1966		1,729,639	2,194	21,853
1967		2,616,924	16,530	22,069
1968		2,878,106	26,979	30,582
1969		2,899,667	12,495	75,481
1970		3,519,623	32,085	361,909
1971		6,482,171	218,570	376,607
1972		6,897,527	37,601	328,030
1973		4,860,000	38,000	200,000
1974		4,860,000	38,000	200,000
1975		5,200,000	75,000	200,000
1976		6,015,600	360,000	200,000
1977		7,035,000	360,000	200,000
1978		8,940,000	425,000	200,000
1979		12,170,000	715,000	200,000
1980		14,890,000	1,360,000	200,000
1981		17,270,000	1,650,000	200,000
1982		19,820,000	2,040,000	200,000
1985		19,850,000	2,040,000	200,000
1990		30,000,000	3,060,000	200,000
1995		45,000,000	4,600,000	200,000
2000		60,000,000	6,300,000	200,000

SOUTH DAKOTA

Year	FOSSIL FUEL CONSUMED			Gas Mcf
	Bit. Coal Short Tons	Lignite Short Tons	Oil 42 Gal. Bbls	
1960	220,867	33,697	47,397	6,453,944
1961	214,326	26,567	47,880	4,894,042
1962	242,608	13,367	86,936	3,800,798
1963	239,137	10,698	53,827	4,319,871
1964	231,467	4,616	39,107	4,161,372
1965	233,376	3,851	55,079	3,359,272
1966	300,300	9,383	60,436	3,656,060
1967	237,032	30,148	69,627	3,656,600
1968	238,586	12,356	67,963	3,767,379
1969	256,231	18,821	105,828	3,475,556
1970	267,310	33,748	318,250	4,363,885
1971	280,639	22,167	212,028	3,318,598
1972	272,606	12,638	317,637	3,562,805
1973	280,000	20,000	396,000	3,300,000
1974	280,000	20,000	396,000	3,300,000
1975	280,000	975,000	683,000	3,300,000
1976	280,000	1,962,000	600,000	3,300,000
1977	280,000	1,962,000	600,000	3,300,000
1978	280,000	1,962,000	680,000	3,300,000
1979	280,000	1,962,000	722,000	3,300,000
1980	280,000	1,962,000	738,000	3,300,000
1981	280,000	2,176,000	798,000	3,300,000
1982	280,000	2,415,000	810,000	3,300,000
1985	280,000	5,036,000	1,020,000	3,300,000
1990	280,000	9,370,000	2,040,000	3,300,000
1995	280,000	15,786,000	2,890,000	3,300,000
2000	170,000	26,762,000	4,386,000	3,300,000

ELECTRIC UTILITY FOSSIL FUEL CONSUMPTION IN ELECTRIC GENERATING PLANTS
1960 - 1972 Actual
1973 - 2000 Projected

MONTANA

Year	Bit. Coal Short Tons	FOSSIL FUEL CONSUMED		Gas Mcf
		Lignite Short Tons	Oil 42 Gal. Bbls	
1960		106,818	72	341,270
1961		262,406	21	356,293
1962		294,560	1,264	3,712,380
1963		285,675	671	3,303,106
1964		293,763	3,592	2,649,559
1965		295,876	710	1,992,313
1966		323,395	82,112	2,977,256
1967		325,584	6,181	502,475
1968	69,795	329,511	22,831	631,200
1969	270,657	305,910	104,078	1,519,098
1970	603,079	319,503	26,919	2,529,457
1971	346,786	325,263	197	1,074,872
1972	648,515	320,230	17,440	1,217,530
1973	500,000	330,000	100,000	1,000,000
1974	500,000	330,000	100,000	1,000,000
1975	1,000,000	330,000	170,000	1,000,000
1976	2,000,000	330,000	510,000	1,000,000
1977	2,000,000	330,000	510,000	1,000,000
1978	3,100,000	330,000	660,000	1,000,000
1979	6,600,000	330,000	1,090,000	1,000,000
1980	7,700,000	330,000	1,260,000	1,000,000
1981	7,700,000	330,000	1,260,000	1,000,000
1982	7,700,000	330,000	1,260,000	1,000,000
1985	7,700,000	3,400,000	1,630,000	1,000,000
1990	12,400,000	3,400,000	2,210,000	1,000,000
1995	16,300,000	6,350,000	2,890,000	1,000,000
2000	19,000,000	9,350,000	3,060,000	1,000,000

WYOMING

Year	FOSSIL FUEL CONSUMED			Gas Mcf
	Bit. Coal Short Tons	Lignite Short Tons	Oil 42 Gal. Bbls	
1960	615,466		11,796	670,686
1961	1,054,158		18,322	617,472
1962	1,106,057		4,605	706,076
1963	1,672,229		26,203	214,580
1964	1,752,108		13,319	152,003
1965	1,943,159		34,167	162,602
1966	2,430,708		15,108	149,785
1967	2,276,174		26,227	158,567
1968	2,389,900		30,022	659,032
1969	3,068,398		27,568	2,424,729
1970	3,570,605		24,563	2,373,004
1971	3,600,255		99,743	2,981,223
1972	4,552,745		122,950	2,057,208
1973	4,990,000		850,000	1,000,000
1974	5,780,000		1,800,000	1,000,000
1975	6,930,000		1,950,000	1,000,000
1976	8,500,000		2,180,000	1,000,000
1977	10,000,000		2,340,000	1,000,000
1978	10,700,000		2,450,000	1,000,000
1979	10,700,000		2,450,000	1,000,000
1980	10,700,000		2,450,000	1,000,000
1981	10,700,000		2,450,000	1,000,000
1982	10,700,000		2,450,000	1,000,000
1985	10,700,000		2,450,000	1,000,000
1990	12,400,000		3,000,000	1,000,000
1995	16,600,000		3,360,000	1,000,000
2000	22,400,000		4,760,000	1,000,000

ELECTRIC UTILITY FOSSIL FUEL CONSUMPTION IN ELECTRIC GENERATING PLANTS

1960 - 1972 Actual
1973 - 2000 Projected

NEBRASKA

Year	FOSSIL FUEL CONSUMED Bit. Coal Short Tons	Lignite Short Tons	Oil 42 Gal. Bbls	Gas MCF
1960	255,616		159,528	30,972,825
1961	209,043		158,370	33,098,999
1962	387,672		212,392	32,341,286
1963	465,335		257,894	36,475,819
1964	500,976		151,398	37,661,422
1965	485,918		177,830	36,268,845
1966	417,193		126,505	39,502,712
1967	501,109		109,558	39,478,480
1968	533,529		131,138	48,568,162
1969	900,906		185,560	45,169,907
1970	1,005,692		313,870	47,641,012
1971	946,701		218,283	48,891,564
1972	1,228,112		455,025	49,138,668
1973	1,550,000		1,700,000	46,000,000
1974	1,200,000		1,700,000	46,000,000
1975	1,200,000		1,700,000	46,000,000
1976	1,200,000		1,700,000	46,000,000
1977	1,300,000		1,700,000	46,000,000
1978	1,600,000		2,700,000	46,000,000
1979	2,400,000		2,700,000	46,000,000
1980	3,200,000		2,700,000	46,000,000
1981	4,100,000		2,700,000	46,000,000
1982	2,300,000		2,700,000	46,000,000
1985	4,500,000		2,900,000	46,000,000
1990	5,300,000		3,400,000	46,000,000
1995	6,900,000		4,300,000	46,000,000
2000	9,100,000		6,800,000	46,000,000

United States Department of the Interior
BUREAU OF RECLAMATION
Upper Missouri Region
P.O. Box 2553
Billings, Montana 59103

IN REPLY
REFER TO: 620
123.-

NOV 2 7 1973

Mr. James A. West
Group Leader, National Energy
Considerations Work Group
Northern Great Plains Resource Program
U. S. Department of the Interior
Interior Building
Office of the Secretary
Washington, D.C. 20240

Subject: First Draft, National Energy Considerations Report - Northern Great Plains Resource Program

Dear Mr. West:

Enclosed is a copy of Table 5.14 from the subject report that has been marked to reflect figures as listed in the April 1973 MARCA R-362 Report. Also, notes have been added to clarify some of the planned and proposed additions.

A question was raised at the November 16, 1973, meeting in Billings about REA additions being included in the Table. The following REA additions are included:

Center 2	Minnkota	400 mw
Lignite 1	CPA & UPA	400 mw
Lignite 2	CPA & UPA	400 mw
Proposed	Basin	500 mw

The Basin unit would be the first step in a proposed 1982 development to 1200 mw. The location has not yet been selected. Although Basin's offices are located in North Dakota, their load commitments cover all of the five states in the study area plus a portion of Colorado and Iowa; therefore, the plant location may not be actually in the North Dakota area as indicated.

JOHNNY HORIZON

It should be recognized that much of the generation as scheduled on Table 5.14 will serve load growth within the five-state area.

Sincerely yours,

Thomas L. Weaver

Thomas L. Weaver
Participant of National Energy
Considerations Work Group

Enclosure

Table 5.14 Northern Great Plains Region--Projected Additions of Electric Generating Capacity, 1973-1982[1]

Plant Name & Company		Capacity(MW)	Fuel Type	Scheduled Operation Date
NORTH DAKOTA:				
Leland Olds 2	(BEPC)	438	lignite	10/75
Center 2	(MPCoop)	435 400	lignite	5/77
Lignite 1	(CPA)	400 [c]	lignite	11/78
Lignite 2	(CPA)	400 [c]	lignite	11/79
Proposed	(BEPC)	500 [b]	lignite	5/79
Proposed	(MDU)	20	oil, gas	5/80
Proposed	(MDU)	100 [a]	lignite	5/81
Proposed	(NSP)	800	lignite	5/81
Proposed	(OTPC)	200 [a]	lignite	5/81
SOUTH DAKOTA:				
Big Stone	(OTPC)	430 [d]	lignite	5/75
Yankton 4	(NWPS)	6	oil	1/74
Aberdeen	(NWPS)	20	oil, gas	5/78
Mitchell	(NWPS)	20	oil, gas	5/79
Proposed	(NWPS)	20	oil, gas	5/80
Proposed	(NWPS)	100 [a]	coal	5/81
MONTANA:				
Colstrip 1	(MPC)	330	coal	7/75
Colstrip 2	(MPC)	330	coal	7/76
Colstrip 3	(MPC)	700	coal	7/78
Colstrip 4	(MPC)	700	coal	7/79
Libby 1	(Army)	121	hydro	7/75
Libby 2	(Army)	121	hydro	10/75
Libby 3	(Army)	121	hydro	1/76
Libby 4	(Army)	121	hydro	4/76
Libby 5	(Army)	121	hydro	10/82
WYOMING:				
Dave Johnston	(PPL)	330	coal	1972
Jim Bridger 1	(IPC)	500	coal	6/74
Jim Bridger 2	(PPL)	500	coal	9/75
Jim Bridger 3	(PPL)	500	coal	9/76
Wyodak	(PPL)	330	coal	5/77

(continued on following page)

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a. Possibly a joint participation unit to be located in the North Dakota area.

b. The first unit in a proposed staged development of up to 1200 MW by 1982. Location not yet determined but will be within the five state area considered in the report.

c. Joint development of CPA & UPA to be located at Underwood North Dakota.

d. Joint participation unit between OTP, NWPS & MDU.

(Table5.14continued)

Plant Name & Company		Capacity(MW)	Fuel Type	Scheduled Operation Date
NEBRASKA:				
Hebron 1	(NPPD)	50	gas	1973
McCook 1	(NPPD)	48	gas	1973
Sheldon 3 3,4	(NPPD)	50	gas	1973
Jones St. ~~1~~,2	(OPPD)	116	gas	1973
Cooper 1	(NPPD)	778	nuclear	1973
Ft. Calhoun 1	(OPPD)	457	nuclear	1973
Fremont	(FDU)	80	gas, coal	1976
Gentleman	(NPPD)	~~650~~ 600	coal	1977
Proposed	(OPPD)	100	gas, oil	1978
Proposed	(OPPD)	200	gas	1979
Proposed	(NPPD)	200	gas	1980
Ft. Calhoun 2	(OPPD)	900	nuclear	1980
Cooper 2	(NPPD)	1,100	nuclear	1984
N. Omaha 6	(OPPD)	200	coal	1987
Ft. Calhoun 3	(OPPD)	1,100	nuclear	1990

1/ data from Federal Power Commision on 10 year future programmed units as furnished by utility regional reliability councils.

United States Department of the Interior
BUREAU OF MINES
BUILDING 20, DENVER FEDERAL CENTER
DENVER, COLORADO 80225
Intermountain Field Operation Center

October 5, 1973

Memorandum

To: Work Group Leaders, NGPRP

From: Assistant Work Group Leader, Mineral Resources
Work Group, NGPRP

Subject: Revised mine location and production data

Based upon data acquired at our Mineral Resources Work Group meeting October 3, minor changes were made in the coal production table previously sent to you. Please use this revised table in your work.

William G. Park

Enclosure

cc: RL McPhail w/enc

NGPRP coal production - actual and projected Continued

Map No.	Company and mine	Type of mine	1972 Production1/	Est. 1975 Production1/	Est. 1980 Production1/
North Dakota					
20	Baukol Noonan Inc. - Baukol Noonan	Surface	1.44	1.5	4.5
21	North American Coal - Indianhead	do.	1.04	1.2	1.2 3/
22	Knife River Coal Mining Co. - Beulah	do.	1.53	1.5	1.5
23	Consolidation Coal Co. - Glenharold	do.	1.42	4.0	4.0
24	Baukol Noonan Inc. - Noonan Strip	do.	.48	0.0	0.0
25	Consolidation Coal Co. - Velva	do.	.47	.47	.47
26	Knife River Coal Mining Co. - Gascoyne	do.	.16	3.0	3.0
27	Bonsness Coal Mine - Bonsness	do.	Less than .12 MM tons	Not estimated	
28	Underwood Coal Co. Inc.	do. (closed)	do.	do.	
29	Husky Briquetting Inc. - Lehigh Strip	do.	do.	do.	
30	Arrowhead Coal Co. - Arrowhead Strip	do.	do.	do.	
	Unlocatable Mining Operations		Total N.D.	11.67	14.67
	Virgil Smith - Arrowhead, Bowman County		Less than 100,000 tons		
	Sprecher Coal Co. - Sprecher, McLain County		do.		
	Geo Resources, Inc., Williams County		do.		

1/ Production in million tons.
2/ Production plans uncertain.
3/ Possible 5 million tons.

Revised 10/1/73

NGPRP coal production - actual and projected

Map No.	Company and mine	Type of mine	1972 Production1/	Est. 1975 Production1/	Est. 1980 Production1/
Wyoming					
1	Wyodak Resource Development Co. - Wyodak	Surface	.62	1.0	1.5
2	Amax Coal Co. - Belle Ayr	do.	.03	1.75	9.5
3	Best Coal Co.	do.	.001	.001	.001
4	Pacific Power & Light - Dave Johnson	do.	2.62	2.7	2.8
5	Big Horn Coal Co. - Big Horn	do.	.95	.9	1.0
6	Welch Coal Co.	do.	.02	0.0	0.0
	(Announced or proposed operations)				
7	Carter Oil Co.	do.	--	Doubtful production by 1985	
8	Atlantic Richfield	do.	--	.2	7.0
9	Reynolds Metals Inc.2/	do.	--	--	--
10	Kerr-McGee	do.	--	--	7.0
			Total Wyoming (Powder River Basin Only)	6.351	14.801
Montana					
11	Decker Coal Co. - Decker	Surface	.8	6.0	13.0
12	Westmoreland Resources - "Sarpy Creek"	do.	--	4.0	4.0
13	Peabody Coal Co. - Big Sky	do.	1.6	4.0	4.0
14	Western Energy Co. - Colstrip	do.	5.5	5.5	19.32
15	Knife River Coal Co. - Savage	do.	.32	.32	.32
16	Reliable Coal Mining Co.	do.	No report or less than 1,000 tons	Not estimated	
17	Divide Coal Mining Co. - Storm King	(Underground)	Less than .12 MM tons	do.	
18	Western Coal Mining Co.	do.	No report or less than 1,000 tons	do.	
19	Nies Coal Co. - Nies	do.	Less than .12 MM tons	do.	
			Total Montana	19.82	40.64

Major Contracts for Out-of-State Coal Shipments, NGP Region, Federal Lands

STATE	CONSUMER LOCATION	MILLION TONS/YEAR	BEGINNING
WYOMING	Sioux City, Iowa	1.3	existing
"	Council Bluffs, Ia.	1.2	1979
"	Nebraska	4.5	1972-1974
"	W. Nebraska	1.8	1976
"	Rapid City, S.D.	0.5	existing
"	Pueblo, Colo.	2.4	1972
"	Topeka, Kansas	6.4	1978
"	Muskogee, Okla.	3.7	1976
"	Amarillo, Texas	1.0	1975
"	Avinger, Texas	3.5	1977
"	Louisiana	1.7	1978
"	Redfield, Arkansas	5.0	1979
Total Wyoming (Federal Lands)		33.0	
NORTH DAKOTA	Ortonville, S.D.	.25	1974
"	Hoot Lake, Minn.	.20	1974
Total N.D.(Federal Lands)		.45	
MONTANA	Minneapolis, Minn.	0.8	existing
"	Cohasset, Minn.	1.5	existing
"	Becker, Minn.	2.2	existing
"	ST. Paul, Minn.	1.2	1975
"	Wisconsin	0.9	1974
"	St. Clair, Mich.	6.5	1974
"	Chicago, Ill.	1.6	existing
"	" "	5.3	1974
"	American Elec. Pwr	8.3	1974
Total Montana (Federal Lands)		28.3	

DISCUSSION DRAFT--MARCH 1974

PART III.

UNITED STATES ENERGY THROUGH THE YEAR 2000
and
ENERGY CONSERVATION

Introduction

A modern industrial nation, such as the United States, must have the ability to secure and use energy resources. The importance to the national economy of a secure energy supply will continue well into the future. Projections for the near future (the present through 1985) and for the distant future (1985 to 2000) indicate serious domestic supply-demand imbalances in the energy market. Decisions on policy related to energy proposals must be made with the objective of reducing these imbalances.

Historical Perspective on Total Energy Consumption 1/

In the 26-year period from 1947-1973, energy consumption increased each year over the previous year in all but three years, and two of these were recession years. The last decline in annual energy consumption occurred in 1954. Thus, for 20 years each year's energy consumption has exceeded the consumption for the previous year. This is graphically illustrated in Figure 1.

Gross energy consumption increased from 33.0 quadrillion Btu in 1947 to 75.6 quadrillion Btu in 1973. This represents a 3.2 percent annual rate of growth of energy demand. During the same period, net energy inputs 2/ increased from 29.2 quadrillion Btu to 62.2 quadrillion Btu for an average annual rate of growth of 2.9 percent.

1/ The following discussion is based on Tables 1-4 , Appendix III -A.

2/ Gross energy inputs refer to the total inputs to the electrical, industrial, household and commercial, and transportation sectors, and include both fuel and non-fuel uses of energy sources. Net energy inputs refer to the inputs to the final consuming sectors (Industrial, Transportation, and Household and Commercial) with the electrical inputs converted on the basis of 3,412 Btu/kwhr.

The above growth rates cover a 25-year period and are not representative of the growth rates experienced in the recent past, as can be seen in the following tabulation: (by 5-year increments):

Year	Gross energy inputs (Quadrillion Btu)	Average annual growth rate (percent)	Net energy inputs (Quadrillion Btu)	Average annual growth rate (percent)
1950	34.0		29.7	
1955	39.7	3.1	34.3	2.9
1960	44.6	2.3	38.2	2.2
1965	53.3	3.6	45.3	3.5
1970	67.4	4.8	56.0	4.3

The 4.8 percent rate of increase from 1965 to 1970 in gross energy inputs is considerably higher than previous periods, as in the 3.6 percent rate for the 1960-1965 period. In net energy, the same is true for the 4.3 percent rate for 1965-1970, and the 3.5 percent rate for 1960-1965. The increase in energy consumption from 1970 to 1971 was 1.9 percent, but this was strongly influenced by the slow rate of recovery from the 1969-70 recession. The boom experienced in 1972 raised the rate of increase to 4.9 percent. Preliminary estimates for 1973 also indicates a growth rate of 4.9 percent. 1947-1973 gross and net energy inputs are graphically illustrated in Figure 1.

The difference between total gross energy inputs and net energy inputs represents the losses from the conversion of primary fuels to electrical energy, a secondary energy form. If net energy is divided by gross energy, a ratio indicating the percent of total gross energy inputs actually used in the consuming sectors may be derived. This ratio has declined from 88.5 percent in 1957 to 82.3 percent in 1973. This is a rough indicator of the effects of continuing shifts in consumption from primary to secondary forms of energy.

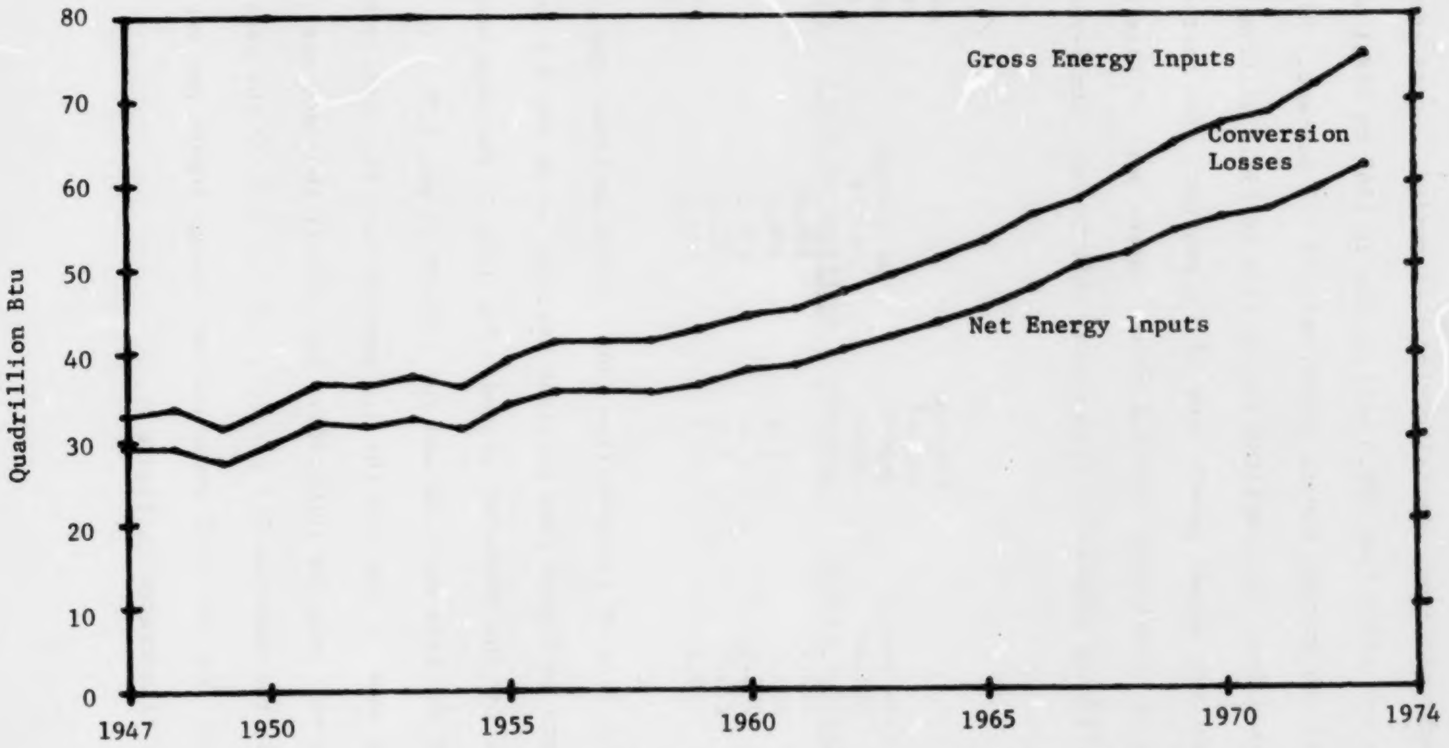

Figure 1 . United States Gross and Net Energy Inputs in Quadrillion Btu
1947-1973 (preliminary)

Another indicator of our increasingly energy intensive society is the energy usage per capital during this period. Gross energy usage per capita has risen from 229.0 million Btu in 1947 to 358.1 million Btu in 1973, an average annual growth rate of 1.7 percent. Net energy use increased from 202.8 million Btu in 1947 to 294.7 million Btu in 1972, an average annual growth rate of 1.5 percent. The most significant rates of growth were confined to the latter part of this period and the following tabulation illustrates this trend: (in 5-year increments):

Year	Gross energy capita (millions of Btu)	Average annual growth rate (percent)	Net energy capita (millions of Btu)	Average annual growth rate (percent)
1950	223.2		194.8	
1955	239.3	1.4	206.7	1.2
1960	246.8	.6	211.5	.5
1965	274.4	2.1	232.1	1.9
1970	329.1	3.7	273.6	3.3

The 3.7 rate of increase from 1965 to 1970 in gross energy per capita inputs is higher than previous periods, as is the 2.1 percent growth rate for the 1960-1965 period. For 1970-71 the rate was .8%, for 1971-72 the rate was 4.0% and for 1972-73 it was 3.7%. In net energy, the same is true for the 3.3 percent rate for 1965-1970 and the 1.9 percent rate for 1960-1965. For 1970-71 the rate was .6 percent, for 1971-72, the rate was 3.5 percent, and for 1972-73 the rate was 3.4 percent. The 1947-1972 gross and net energy inputs per capita are graphically illustrated in Figure 2 .

One further indicator of the trend in energy consumption is the energy consumed per dollar of Gross National Product (GNP) where GNP is measured in constant 1958 dollars. The energy/GNP ratio has a long term downward trend. In 1947, the ratio was 106,400 Btu per dollar of GNP and it declined to a low of 85,700 in 1966. Some anxiety has been expressed because the long term downward trend reversed in 1966 and steadily worked higher until it peaked at 93,600 Btu per dollar of GNP in 1970. This ratio is a rough measure of the efficiency of utilization of energy in the economy and any reversal would indicate a reversal in our long term increases in efficiency. However, the trend reversed slightly in 1971, declining to 92,600 Btu per dollar of GNP. This was followed in 1972 by a further decline in the ratio to 91,300 Btu per dollar of GNP, and an even further decline in 1973 to 89.8 Btu. This may be indicative of a return to the long term downward trend. The 1947-1973 energy/GNP ratio is graphically illustrated in Figure 4 .

The total energy market includes four major consuming sectors: household and commercial, industrial, transportation, and electrical generation. In general the trends for gross consumption indicate that the Household and Commercial Sector is maintaining its relative share, as is the Transportation Sector. In the period 1947-73 the share of total gross energy going to the Household and Commercial sector has fluctuated between 20.4 and 23.0 percent of total gross energy inputs. Transportation's share has only declined from 26.7 to 24.7 percent during this period - relative stability. The share of total gross

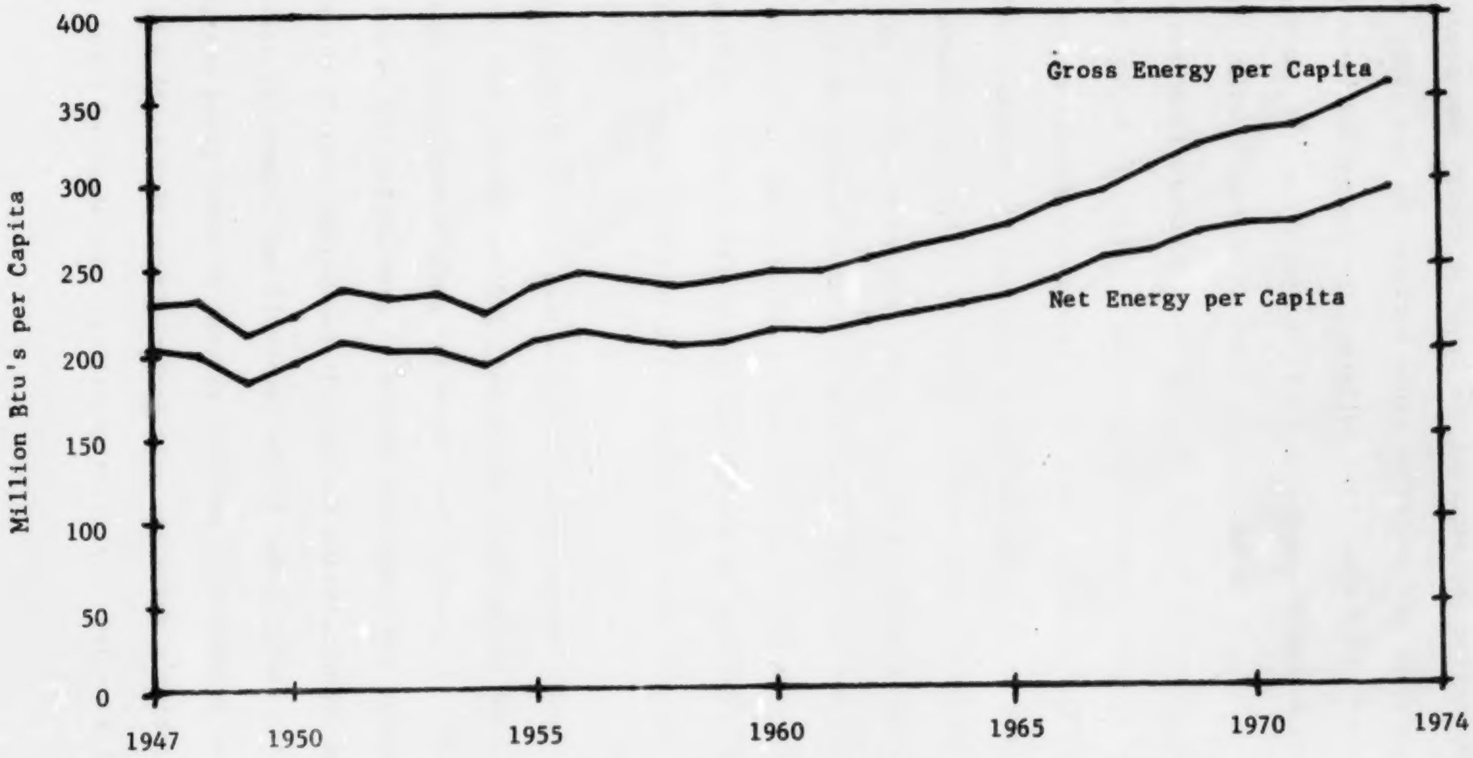

Figure **2** . United States Gross and Net Energy Inputs per Capita in Millions of Btu, 1947-1973(preliminary)

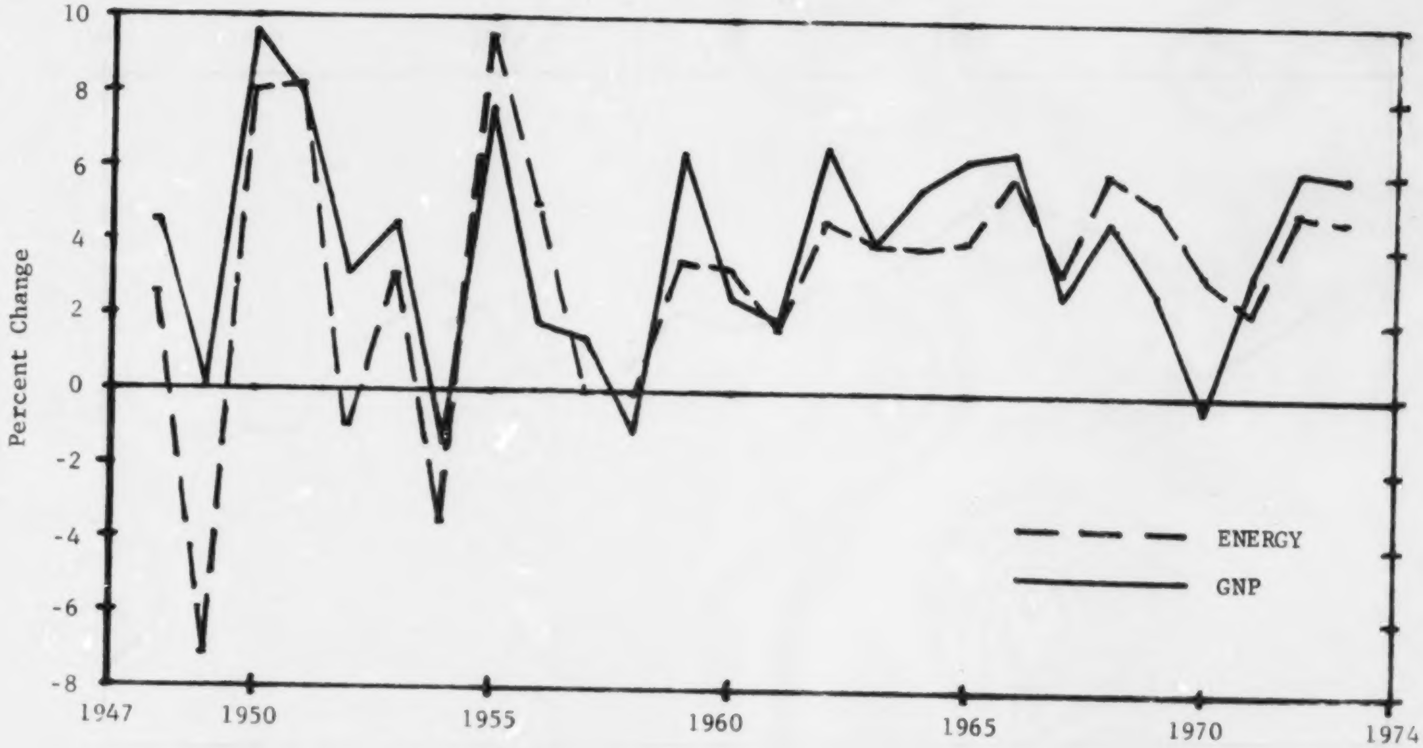

Figure 3. Percent Change in Gross National Product and Percent Change in Gross Energy Inputs, 1948-1973 (preliminary)

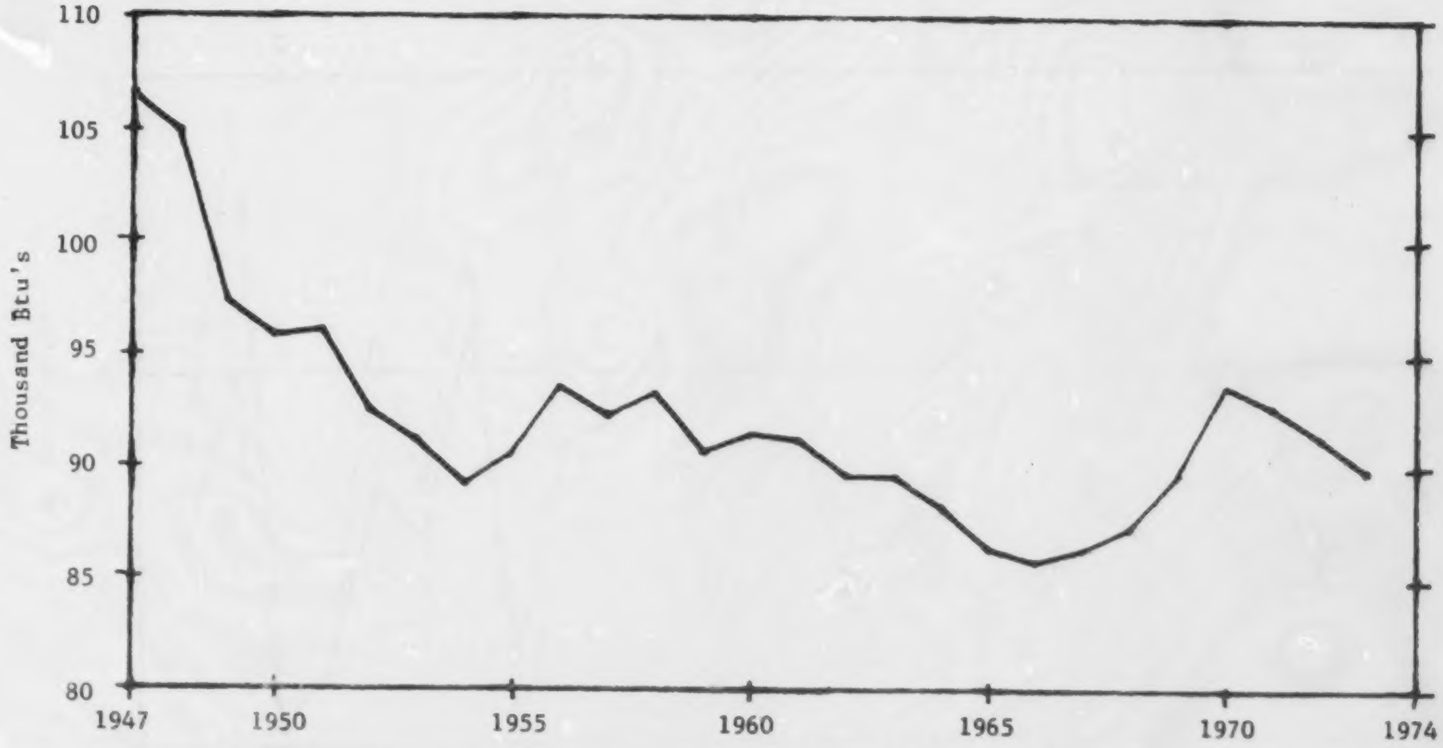

Figure 4 . United States Gross Energy/GNP Ratio in Thousands of Btu per 1958 Dollar, 1947-1973(preliminary) energy going to the Industrial Sector has declined from 38.8 to 28.3 percent, while the share going to the electrical sector has increased from 13.0 to 26.2 percent. This is illustrated in Figure 5.

These gross energy consumption trends must be viewed with caution, for the net energy consumption trends for final consuming sectors tell a different story. In net energy the transportation sector maintains its relative position from 1947 to 1973. The Household and Commercial Sector instead of maintaining its positions gains almost 6 percentage points at the expense of the Industrial Sector. This is indicative of the increasing reliance of the Household and Commercial Sector on electrical energy.

The source of United States energy from 1947 to 1973 has altered. Coal during this period declined from 47.9 percent of total energy inputs to 17.9 percent, while petroleum increased from 34.6 percent to 45.9 percent. Natural gas showed the sharpest increase, moving from 13.6 percent of total energy input to 31.1 percent. Hydropower remained reasonably constant. It's 1947 share was 3.9 percent and its share in 1973 was 3.8 percent. The contribution from nuclear power was negligible, and constituting only 1.2 percent of the total in 1973. This is graphically illustrated in Figure 6 .

Future Energy Supply and Demand

In recent years, many predictions of future energy supply and demand have been attempted. One of the most recent of these studies was done by the Department of the Interior 3/ and forms the basis of

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3/ United States Department of the Interior, United States Energy Through the Year 2000, December 1972. Some changes were made in the forecast to take into consideration changes in the energy scene since completion of the study.

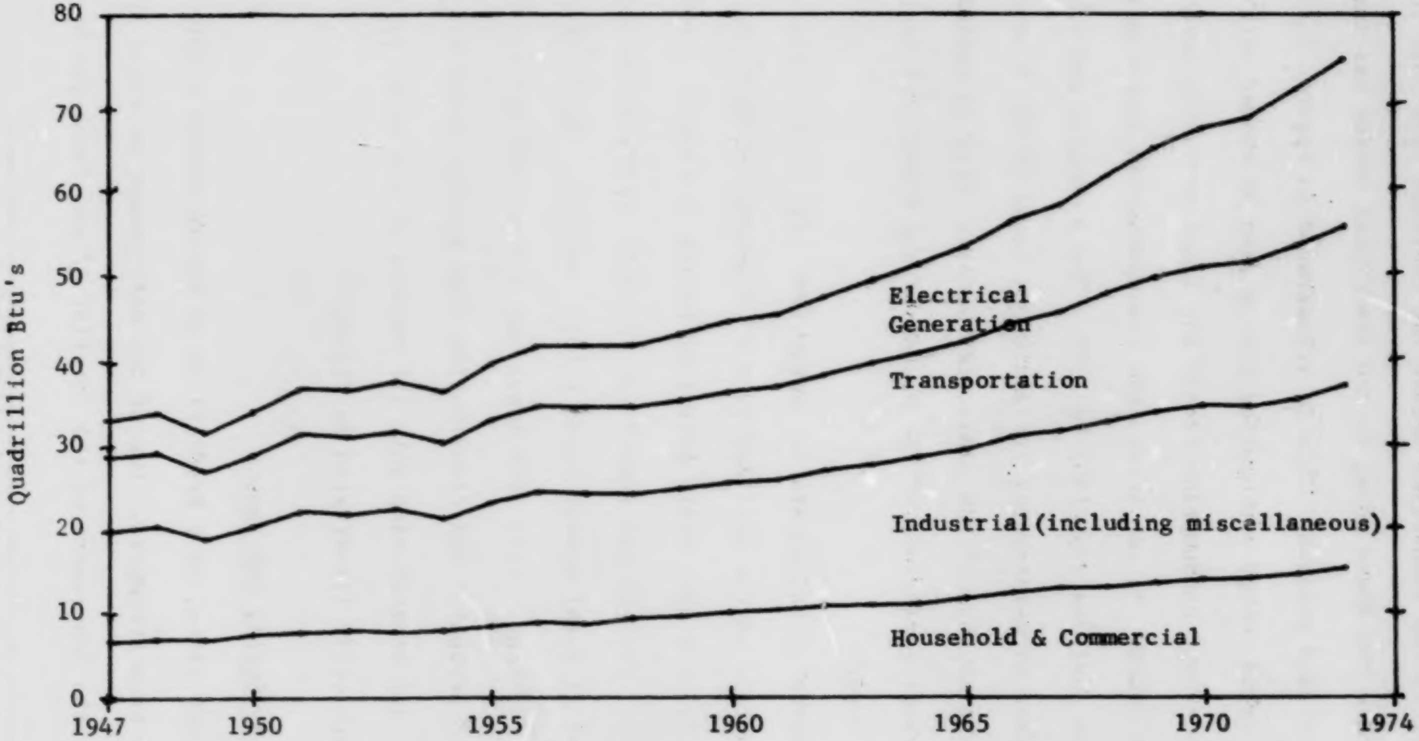

Figure 5 . Gross Energy Inputs by Major Consuming Sector, 1947-1973

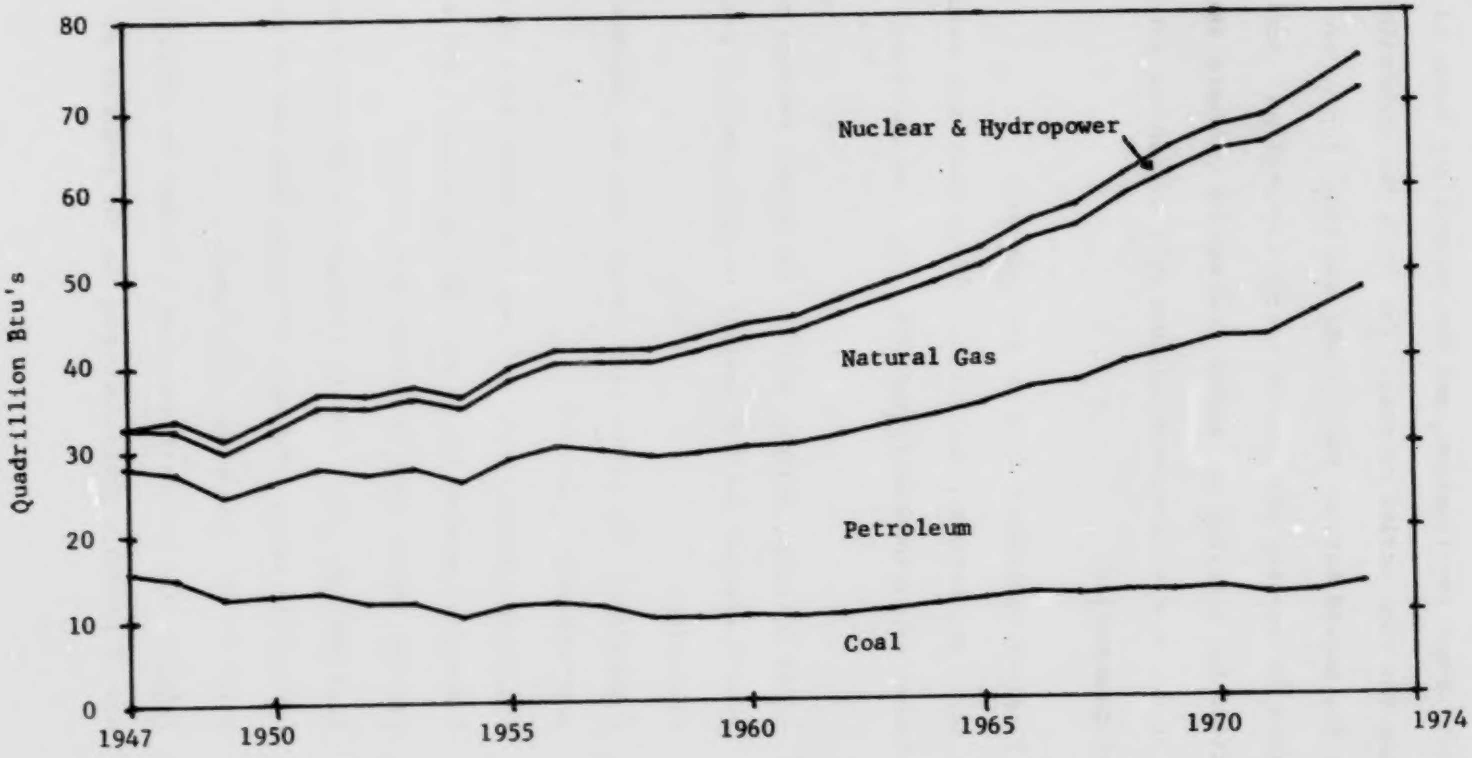

Figure 6 . Gross Energy Inputs by Major Source, 1947-1973(preliminary) projections in this chapter. There is, of course, always some uncertainty about any forecast, and the uncertainty tends to increase the longer the time period covered. For fuels the uncertainty is much less for the period between the present and 1985, for we are essentially locked into our present patterns of energy consumption. After 1985 more options for altering our energy consumption patterns exist, and whether or not we exercise these options will decide our future pattern of energy consumption.

A. The Interior Department Consumption Forecast

For their projections, the Interior Department made assumptions about a number of socioeconomic factors. The most important of these were:

(a) Gross National Product (GNP): The annual average rate of growth assumed was 4.3 percent to 1980, and 4.0 percent thereafter.

(b) Population: The population growth rate was assumed to be approximately 1 percent.

(c) Industrial Production: A 5 percent annual rate of growth of industrial production up to 1980 was assumed, and a 4.4 percent annual rate of growth thereafter.

(d) Fuel Availability: Supply limitations for fuels were explicitly taken into consideration, thus making this a forecast of consumption, not demand.

(e) Prices: The forecast does not consider the effects on energy use of possible sharp increases in the price of energy to consumers. Prices, which in some cases fell in real terms until about 1970, have begun to rise dramatically. This will tend to dampen the exponential increases in energy demand otherwise forecast. Economic studies of energy price imports suggest (but only suggest) that total energy demands may actually level off it this continues. 4/ Unfortunately, at this writing no complete definitive study on price effects or price projections exists, so that demand elasticities were not incorporated into this forecast.

It should also be emphasized that supply elasticities were also not incorporated into this forecast. The same price increases dampening demand may very well stimulate supply of those fuels whose prices rise fastest. The impact on the fuel mix is difficult to evaluate, but it would appear that the mix would be altered.

(f) Technology: The major change in energy technology expected between now and 1985 is development of commercial technique for coal gasification and control of sulfur oxide emissions. The major technological change expected between 1985 and 2000 is commercial introduction of the breeder reactor. Evolutionary increases in the efficiency of utilization of energy were assumed for the entire period. 5/

4/ See, for example, the NSF-RANN study done by Chapman, Tyrrell, and Mount as summarized in Science, Vol. 178, No. 4062 (17 Nov. 1972) pp. 703-708. There is, however, substantial controversy over their results.

5/ These evolutionary increases in efficiency are in addition to any conservation savings. The technological changes are discussed in more detail in the technical sections.

(g) Lifestyle: The present slow trend toward a more service oriented economy is expected to continue.

(e) Energy Conservation: The potentials for conservation of energy were not factored into the original forecast. A recent study by the Office of Energy Conservation, Department of the Interior, gives some indication of possible energy savings from energy conservation. This will be discussed in the section on energy conservation.

Based on these assumptions, the Department of the Interior developed its consumption forecast. The results were: 6/

(1) Gross energy consumption will rise from 75.6 quadrillion Btu in 1973 to 191.9 quadrillion Btu in 2000. This is an annual average growth rate of 3.5 percent.

(2) Net energy consumption will rise from 62.2 quadrillion Btu in 1973 to 139.4 quadrillion Btu in 2000. This is an annual average growth rate of 3.0 percent. Both Gross and Net Energy inputs are graphically illustrated in Figure 7.

(3) The energy/GNP ratio (in thousand of Btu/1958 dollars) will continue to decline from 89.8 in 1973 to 78.7 in 2000. The decline is illustrated in Figure 8.

(4) Gross energy per capita (in millions of Btu/per person) will increase from 358.1 in 1973 to 686.1 in 2000.

(5) Net energy per capita (in millions of Btu/per person) will increase from 294.7 in 1973 to 498.4 in 2000. Both net and gross energy/capita projections are illustrated in Figure 9.

6/ The following discussion is based on Tables 5 through 10, Appendix III-A.

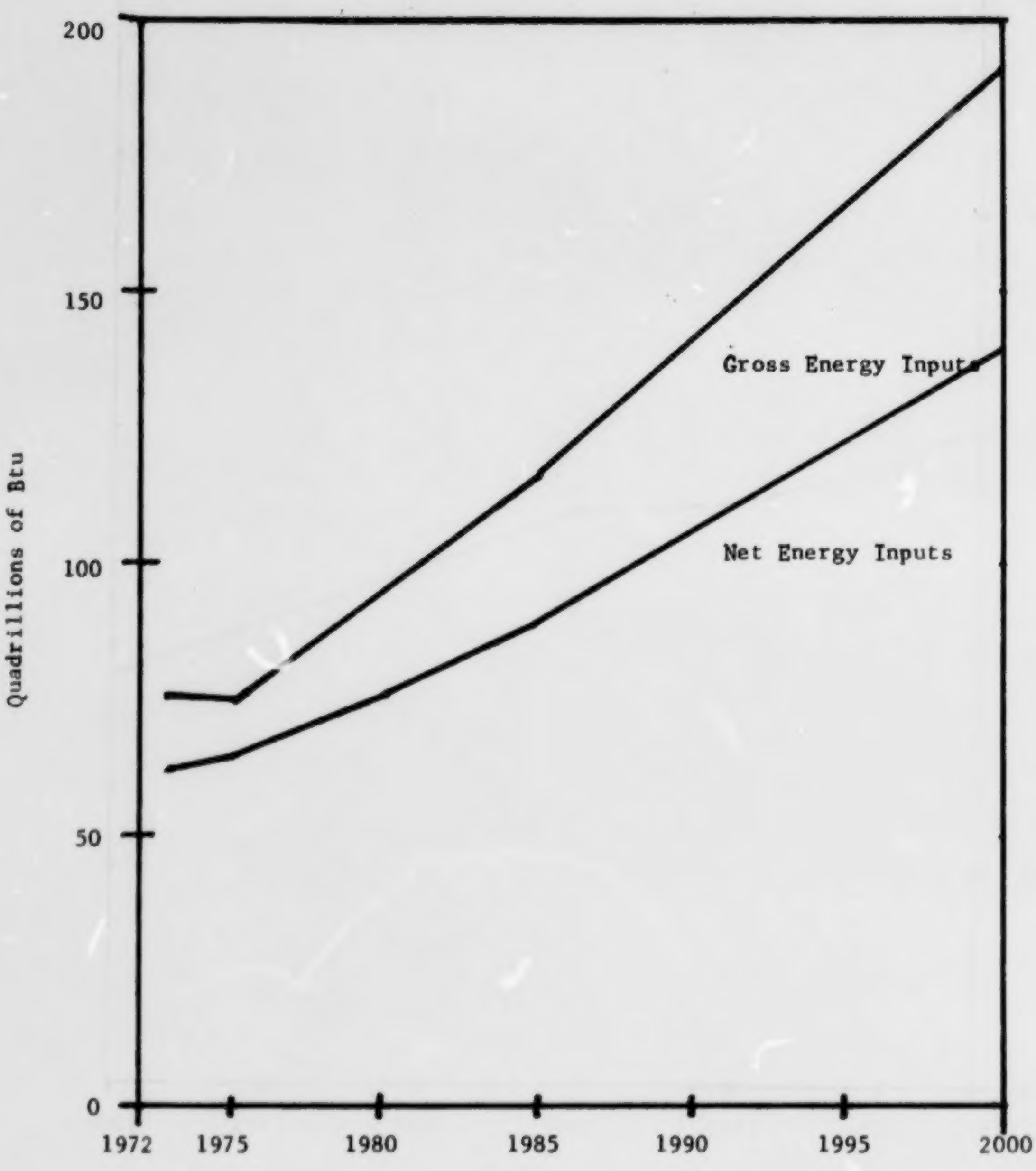

Figure 7. United States Gross and Net Energy Inputs in Quadrillion Btus, 1973-2000

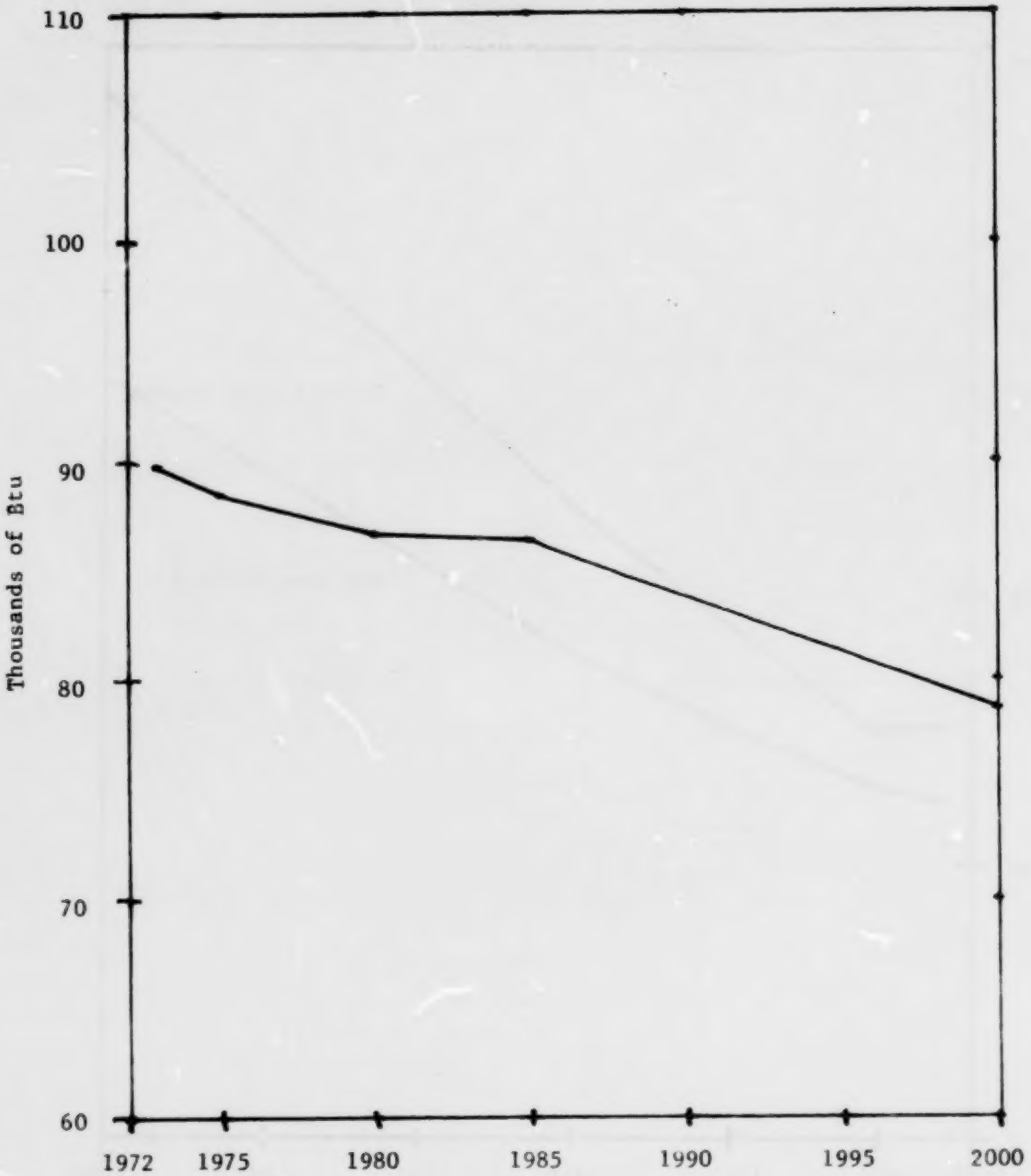

Figure 8. United States Gross Energy/GNP Ratio in Thousands of Btus per 1958 dollar 1973-2000

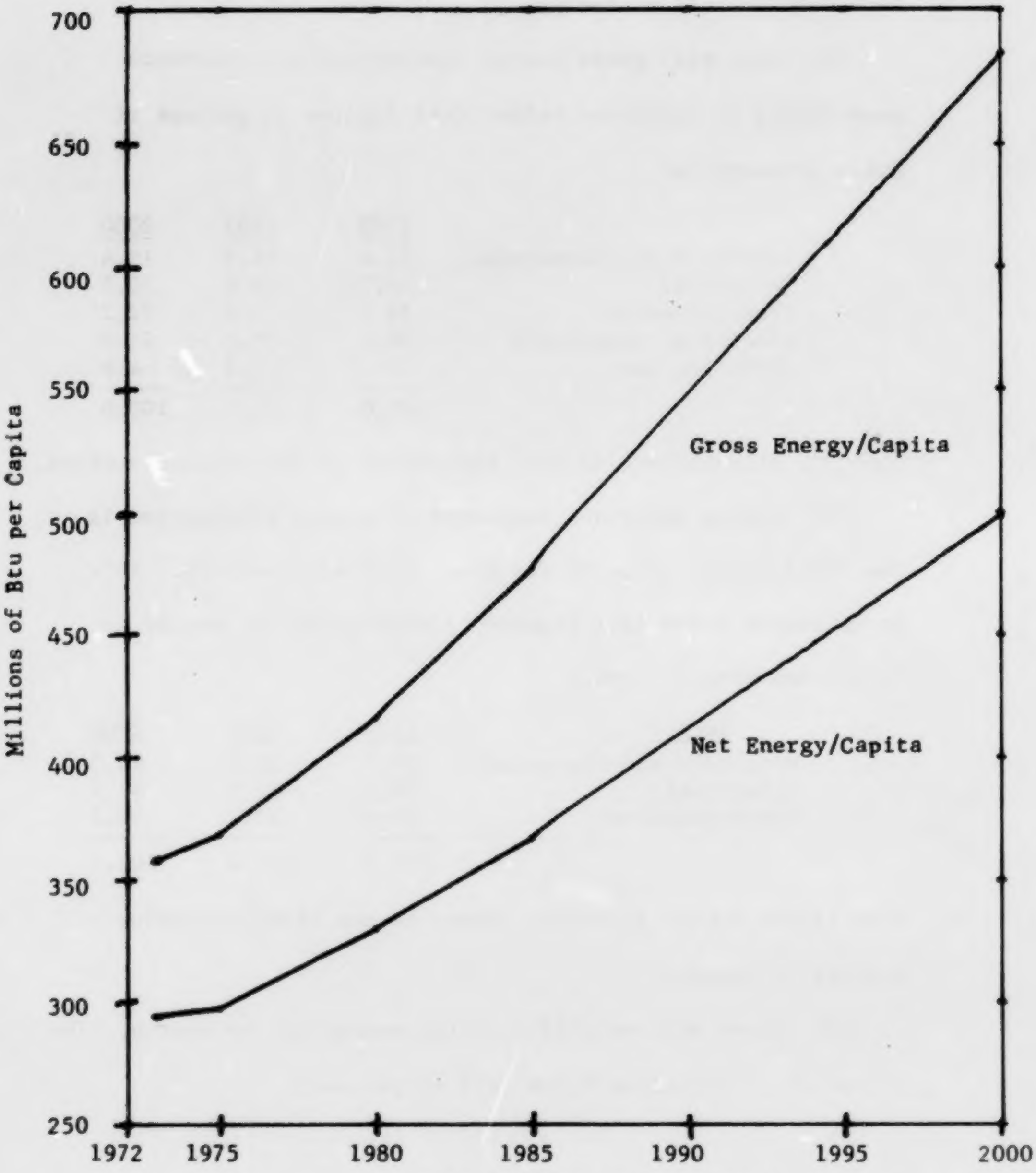

Figure 9. United States Gross and Net Energy Inputs per Capita in Millions of Btu 1973-2000

(6) The energy conversion efficiency of the U.S. will decline from 82.3 percent in 1973 to 72.6 percent in 2000, indicating a continuation in the trend toward greater use of secondary sources of energy.

(7) Sectorial gross energy consumption will indicate some shifts as indicated below: (all figures in percent of total consumption)

	1973	1985	2000
Household and Commercial	20.4	16.3	11.4
Industrial	28.7	23.6	20.5
Transportation	24.7	23.2	22.2
Electrical Generation	26.2	34.6	41.9
Synthetic Gas	--	2.3	4.0
	100.0	100.0	100.0

Figure 10 illustrates, in Btu, the inputs to the various sectors.

(8) A more important indicator of energy consumption is the total energy going to the final consuming sectors. This is indicated below (all figures in percent of net energy to final consuming sectors):

Sector	1973	1985	2000
Household and Commercial	30.7	30.9	28.3
Industrial	39.1	38.9	41.2
Transportation	30.2	30.2	30.5
	100.0	100.0	100.0

This little change in energy inputs to the final consuming sectors is assumed.

(9) There will be shifts in the energy mix by source. The shifts are illustrated below (all in percent):

Source	1973	1985	2000
Petroleum	45.9	44.7	37.2
Natural Gas	31.2	23.5	17.7
Coal	17.9	18.5	16.3
Hydropower	3.9	2.7	1.7
Nuclear Power	1.1	10.1	25.6
Geothermal	1/	0.5	1.4

1/ Included in hydropower.

The most remarkable shift above is the shift to nuclear power. Figure 11 illustrates, in Btu, the various fuel inputs.

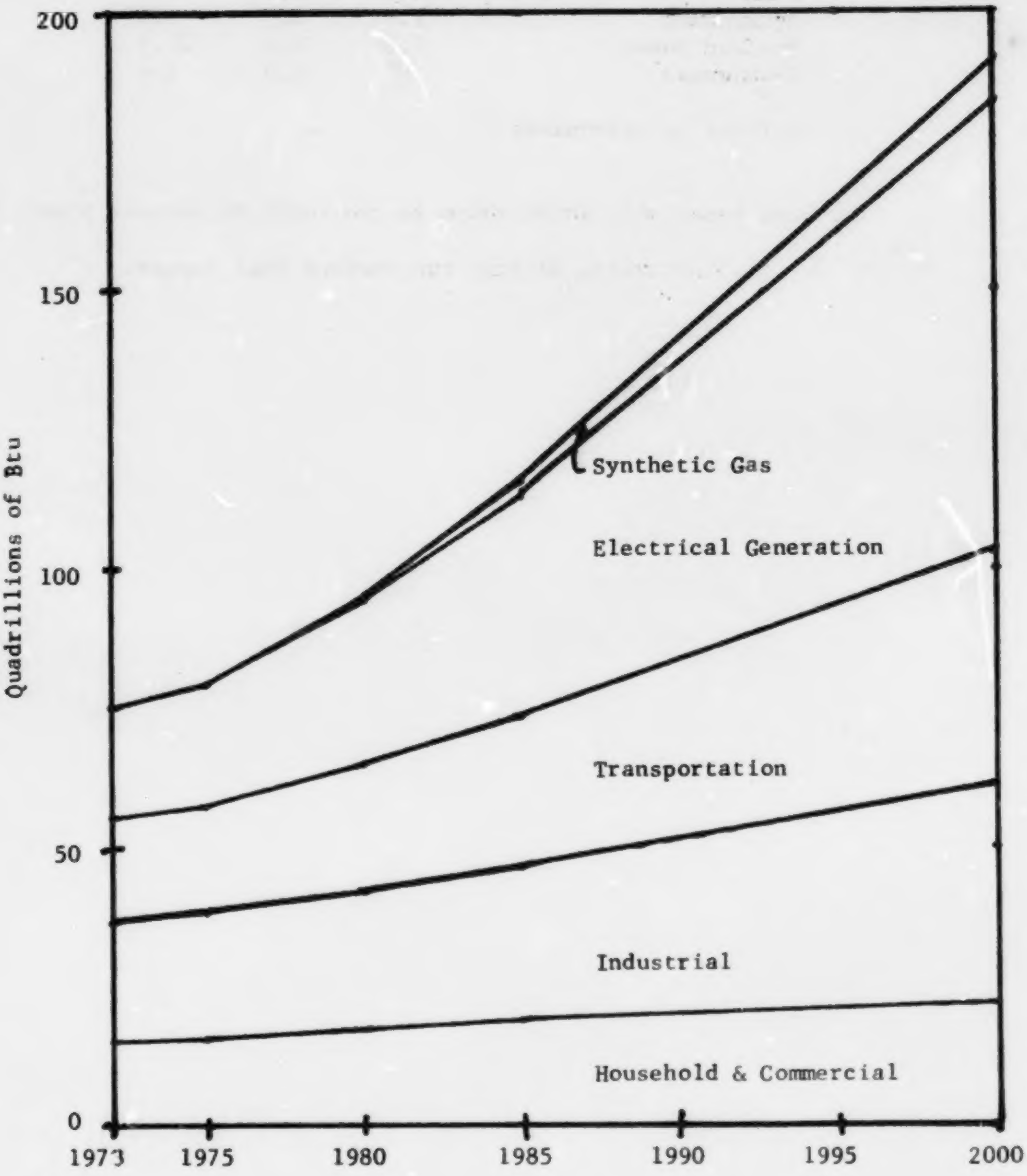

Figure 10 . United States Gross Energy Inputs By Major Consuming Sector in Quadrillions of Btu, 1973-2000

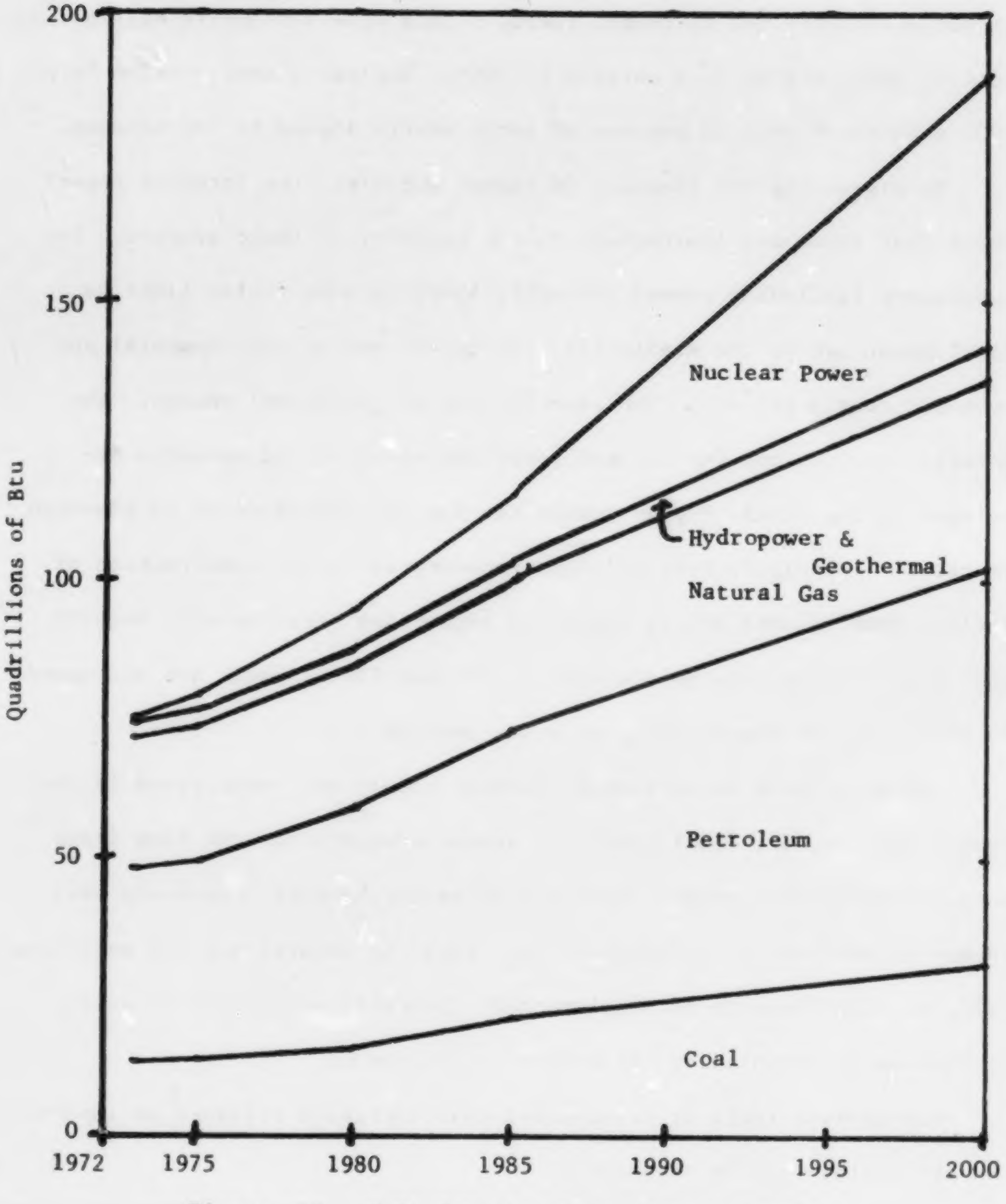

Figure 11. United States Gross Energy Inputs by Major Source in Quadrillions of Btu, 1973-2000

The Interior Department Supply Forecast[7]

As was previously pointed out, our energy requirements will continue to rely heavily on fossil fuels. In 1973 approximately 95 percent of our needs were met by fossil fuels. This will decline to 86.7 percent by 1985, and to 72.3 percent by 2000. Nuclear's contribution by 2000 will reach over 25 percent of total energy inputs to our economy.

In discussing the adequacy of energy supplies, the Interior report noted that there are limitations to the capacity of these sources. For hydropower (including pumped storage), there is some finite limit to development set by the availability of sites, and by environmental and economic considerations. The same is true of geothermal energy. The Interior projections for nuclear power are based on the scenario developed by the Atomic Energy Commission for the introduction of advanced reactors. Any significant problems encountered in the construction of nuclear power plants and in supply of supporting services will require that fossil fuels take up the slack. The non-fossil fuels are discussed in detail in the Electrical Generation section.

The major problem of energy resource supply are encountered in the fossil fuel sector. Coal resources appear adequate for the time frame encompassed by this study. Problems do exist, however, vis-a-vis environmental and capital considerations. Domestic natural gas and petroleum will, however, have to be supplemented. Domestic production of energy by sources is graphically illustrated in Figure 12.

For gaseous fuels it is expected that increased reliance on imports and synthetics will be necessary.

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[7] The following discussion is based on Tables 11, 12 and 13 of Appendix III-A.

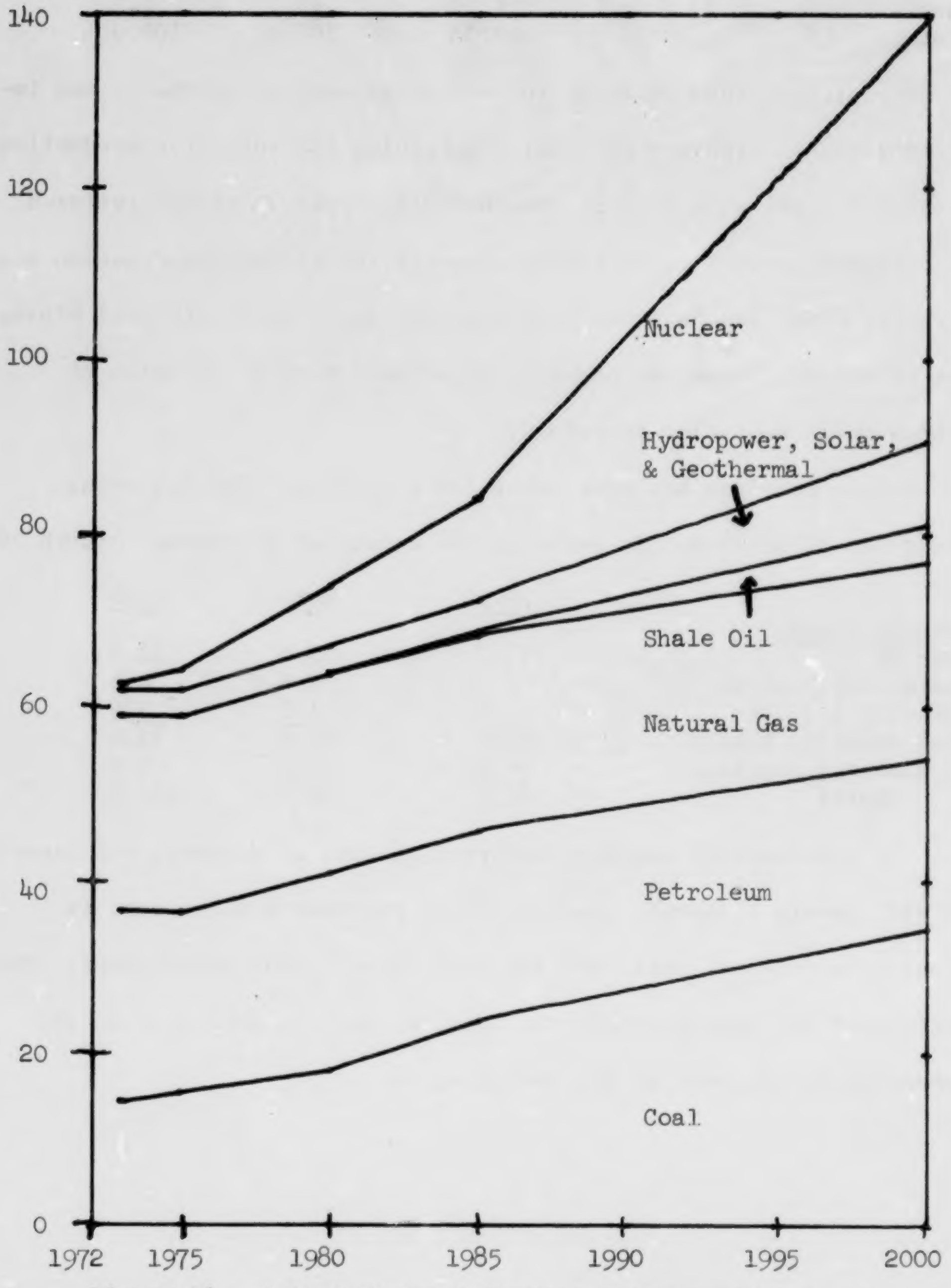

Figure 12. United States Potential Gross Production of Energy Resources by Major Sources in Quadrillion Btu, 1973-2000

The breakdown by percent is as follows:

	1973	1985	2000
Conventional natural gas	95.5	77.0	57.9
Synthetic gas	-	6.8	13.9
Imports	4.5	16.2	28.2
Total	100.0	100.0	100.0

The picture induced is of increased reliance on synthetic and imported gas(both pipeline and LNG). Achieving the indicated production of synthetic gas will require considerable effort. Further research and development will be necessary, capital for plants construction must be forthcoming, and environmental problems associated with coal mining must be solved. Numerous problems associated with importation of gaseous fuels must also be solved.

Supply problems are more acute for petroleum. The following tabulation illustrates, in percent, the source of petroleum through 2000:

	1973	1985	2000
Domestic Supply			
Lower 48	63.7	35.0	22.8
Alaskan North Slope	-	7.8	4.8
Synthetic Liquids	-	1.0	5.9
Total Domestic Supply	63.7	43.8	33.4
Supplemental Supplies	34.3	56.2	66.6
Total	100.0	100.0	100.0

The supplemental supplies referred to are, at present, all imports and will remain primarily imports unless government intervenes to stimulate additional shale oil and coal liquefaction development. The development of these supplemental supplies will be dependent on the commercial development of new technologies.

Energy Conservation in the United States [1]

The demand for energy in the United States rose at an average annual rate of 4.2 percent for the 1960-70 decade. Projections of energy demand for the decade of 1970-80 indicate an average rate of growth of 3.6 percent, for 1980-90 the rate is 3.9 percent, and for 1990-2000 the rate is 3.1 percent. The energy demand and rate of growth for these periods are illustrated in the following table:

Year	Gross energy inputs (trillions of Btu) 1/	Average annual rate of growth (percent)
1960	44,565	
1970	67,444	4.2
1980	96,020	3.6
1990	140,080	3.9
2000	191,900	3.1

1/ Based on Department of the Interior forecast, U.S. Energy Through the Year 2000, Dec. 1972.

The stress on both capital and natural resources to sustain these rates of consumption of energy appears obvious. Lessening of these demands would lower the requirements for both types of resources. Although capital resources are important, this section will concentrate on the natural resources side of energy problems.

To lessen demand for energy requires one of two approaches. Either demand can be decreased by more efficient use of energy (i.e., we avoid energy utilization techniques that are inherently less efficient than the alternatives) or we devise techniques for discouraging the growth in demand for energy. An example of the former would be development of a less energy intensive transportation mode, and an example of the latter would be a fuel tax designed to discourage consumption.

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[1] The following discussion is based on Tables 1 through 6, Appendix III-B.

Unfortunately, the whole question of energy conservation is in a state of flux, as very few definitive studies have been completed. We do, however, have knowledge of viable candidates for energy conservation.

The Stanford Research Institute 2/ breakdown of end use energy consumption in the United States was used to determine a base. Basically this showed that the Household and Commercial Sector used 30.5% of net energy, the Industrial Sector used 37.4% and the transportation sector used 31.4. Obviously any end use of energy that requires only a small percentage of the national demand for energy cannot be altered sufficiently to significantly affect energy demand. If only those end uses of energy utilizing over 3 percent each of our total net energy uses are considered viable candidates for energy conservation measures, then our candidates are:

2/ Stanford Research Institute, Patterns of Energy Consumption in the United States (Government Printing Office, Wash., D.C., 1972) The data for 1968 used by SRI was extrapolated to 1970 and reconciled with actual data.

Sector	Percent of net energy consumption
Household and Commercial	
Heating and air conditioning	22.4
Water heating	3.7
Industrial	
Process steam	20.2
Electric drive	3.4
Direct heat	13.1
Transportation	
Fuel	31.4

To this must be added conversion losses in the electrical sector. Initial research efforts are being directed at these areas.

It should be noted that "United States Energy Through The Year 2000" incorporated considerable energy savings in the electrical and industrial sectors. In the electrical sector the heat rate for fossil fueled fired steam plants was assumed to decline from 10,494 Btu/Kwhr in 1971 to 8500 Btu/Kwhr in 2000 for a 19% gain inefficiency. For nuclear power plants the heat rate was assumed to decline from 10,660 Btu/Kwhr (representing LWR technology) to 9000 Btu/Kwhr (representing a nuclear mix of HTGR, LMFBR, & LWR technology) for an efficiency gain of 15.5%.

In the industrial sector the energy input (in thousands of Btu) per dollars of value added (in constant 1958 dollars) was assumed to decline from 101 to 79 indicating a gain in efficiency of 21.7 percent. The term indicate is used because the lessening of energy intensiveness in this is usually due to more than increased efficiency utilization of energy. Other contributing factors would be the changing mix of goods from energy intensive products to less energy intensive products and the shift to electricity with its consequent shift of losses to the electrical sector.

However, even with these savings additional savings are possible. Based on an unpublished study by the Office of Energy Conservation [3] the savings in net energy from conservation were based on the following increases in efficiency: [4]

	1985	2000
Household & Commercial	1.3	6.2
Industrial	15.3	19.6
Transportation	16.3	20.8
Total	11.2	16.2

The results of assuming these increases in efficienty of energy utilization was to reduce energy consumption in these sector by the following amounts (all figures in trillions of Btu):

	1985	2000
Household & Commercial	350	2,470
Industrial	5,330	11,340
Transportation	4,410	8,870
Total	10,090	22,680

This represents a 8.6 percent reduction in energy consumption by 1985, and an 11.6% decrease by 2000. The actual reductions in the fuels are as follows:

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[3] Seidel, Marquis, Demand Curtailment and Conservation, January 7, 1974. Cited and used by special permission of the author. Copies of the report not available.

[4] These areas of savings are all consistent with those areas of energy consumption utilizing 3% or more of total net energy.

	1985	2000
Coal, millions tons	61	117
Petroleum, million bbls.	995	2,143
Natural gas billion cubic feet	2,909	6,344
Electricity, billion kwhrs.	35	430

It cannot be stressed too strongly that these conservation savings are predicated upon estimated possible increases in efficiency that may or may not, be realizable. All appear plausible in view of present technology, but further study will be necessary to verify their plausibility. Before leaving the subject there are five points that need to be set out in the field of energy conservation:

(1) Energy conservation is not an acceptable goal when the end result is to significantly increase use of other resources (including capital).

(2) The impact of population on energy consumption is more complex than is normally assumed. A given increase in population will require a more than proportionate increase in energy because of the necessity for greater social overhead capital such as water and sewage systems, roads, schools, etc. In other words, the per capita impact on energy consumption of increased population is non-linear.

(3) Many opportunities for energy conservation are dependent on other social and economic trends so worthy of consideration in their own right that it is inappropriate to consider them solely as energy conservation measures. Two important examples are (1) actions to curb the rate of growth of population and (2) gross national product.

(4) Energy conservation can impact the rate of economic growth in this Nation and this requires additional study.

(5) The quality of energy is not equal between fuels. Some energy sources allow us to do things impossible, or else very difficult, with other sources. Some examples: electrical lighting is more efficient (even with conversion losses) than lighting using coal; electric motors allow us to put power where needed more efficiently than other sources; and gasoline is easier to use in automobiles than coal or natural gas.

Some of the long term areas of conservation, either under study contemplated for study, or considered worthy of study are:

Transportation Sector:

(a) The impact of a shift in modal mix to less energy intensive modes.

(b) The impact of increases in load factors for urban travel, aircraft, etc.

(c) Methods for improving the efficiency of vehicles.

(d) The effects of increases in fuel taxes.

(e) The effects of taxes on less efficient vehicles.

(f) The impact of restricting use of automobiles in cities.

Household and Commercial Sector:

(a) The effects of increased insulation of buildings to reduce heating and cooling loads.

(b) A re-examination of present day lighting level requirements.

(c) The impact of total energy systems.

(d) The effects of improving appliance efficiency.

(e) The effect of reduction (or elimination) or resistance heating in favor of heat pumps or fossil-fuel fired heating plants.

Industrial Sector:

(a) The effects of increased recycling of energy-intensive materials.

(b) A re-examination of industrial process energy efficiency.

(c) The use of conversion losses from powerplants as heat sources for direct heat and process steam.

(d) The effects of increased efficiency of motors and engines.

(e) Increased fuel taxes to dampen demand.

(f) The impact of fast write-off for tax purposes of new capital investment that reduces energy consumption.

Electrical Sector:

(a) An examination of the institutional changes necessary to allow utilities to move faster to the scale frontier.

(b) The effects of introduction of advanced power cycles.

(c) The effects of restructuring rates to dampen demand.

(d) An analysis of the impact of inverted rates.

The impact of these proposed studies is not known. That energy will be saved through implementation of some, or all, of these policies is undoubted, but the quantities of savings must be more carefully analyzed.

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APPENDIX III-A.

U.S. ENERGY CONSUMPTION AND PRODUCTION HISTORICAL AND PROJECTED, BY SOURCE AND SECTOR

Table 1.- Selected United States Economic and Energy Indicators
(1947-1973)

Year	Gross energy input[1] (Quadrillion Btu)	Net energy input[2] (Quadrillion Btu)	Population (Millions)	Gross National Product (Billion of $ 1958)	Energy/GNP (1000's of Btu)	Gross energy/capita (Millions of Btu)	Net energy/capita (Millions of Btu)	Conversion Efficiency (Percent)[3]
1947	33.0	29.2	144.1	309.9	106.4	229.0	202.8	88.5
1948	33.9	29.1	146.6	323.7	104.7	231.2	198.6	85.8
1949	31.5	27.3	149.2	324.1	97.2	211.1	182.7	86.5
1950	34.0	29.7	152.3	355.3	95.7	223.2	194.8	87.3
1951	36.8	32.1	154.9	383.4	96.0	237.6	206.9	87.1
1952	36.5	31.6	157.6	395.1	92.4	231.7	200.6	86.6
1953	37.6	32.6	160.2	412.8	91.1	234.7	201.1	85.7
1954	36.3	31.2	163.0	407.0	89.2	222.7	191.5	86.0
1955	39.7	34.3	165.9	[illegible]	90.6	239.3	206.7	86.4
1956	41.7	35.8	168.9	446.1	93.5	246.9	211.7	85.7
1957	41.7	35.6	172.0	452.5	92.2	242.4	206.9	85.4
1958	41.7	35.5	174.9	447.3	93.2	238.4	202.8	85.1
1959	43.1	36.4	177.8	475.9	90.6	242.4	205.0	84.6
1960	44.6	38.2	180.7	487.7	91.4	246.8	211.5	85.7
1961	45.3	38.7	183.8	497.2	91.1	246.5	210.6	85.8
1962	47.4	40.5	186.5	529.8	89.5	254.1	217.2	85.5
1963	49.3	42.0	189.2	551.0	89.5	260.5	222.0	85.2
1964	51.2	43.6	191.8	581.1	88.1	266.9	227.3	85.5
1965	53.3	45.3	194.2	617.8	86.3	274.4	232.1	85.0
1966	56.4	47.6	196.5	658.1	85.7	287.0	242.2	83.8
1967	58.3	50.4	198.6	675.2	86.3	293.5	253.8	86.4
1968	61.7	51.7	200.6	706.6	87.3	307.5	257.7	83.7
1969	65.0	54.4	202.6	724.7	89.7	320.8	268.5	83.7
1970	67.4	56.0	204.8	720.0	93.6	329.1	273.6	83.1
1971	68.7	57.0	207.0	741.7	92.6	331.9	275.4	83.0
1972	72.1	59.5	208.8	789.5	91.3	345.3	285.0	82.6
1973 p/	75.6	62.2	211.0	841.3	89.8	358.1	294.7	82.3

p/ Preliminary

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[1] Gross energy is the total of inputs into the economy of the primary fuels (petroleum, natural gas, and coal, including imports) or their derivatives, plus the generation of hydro and nuclear power converted to equivalent energy inputs.

[2] Net energy is the sector inputs (household and commercial, transportation, and industrial), and consists of direct fuels and purchased electricity.

[3] The conversion efficiency factor is the percent of total gross energy going into the sectors.

Table 2. United States total gross consumption of energy resources by consuming sector 1/
(1947-1973p)

Year	Household & Commercial Quadrillion Btu	Household & Commercial Percent of Total	Industrial Quadrillion Btu	Industrial Percent of Total	Transportation Quadrillion Btu	Transportation Percent of Total	Electricity Generation Quadrillion Btu	Electricity Generation Percent of Total	Miscellaneous Quadrillion Btu	Miscellaneous Percent of Total	Total Gross Energy Inputs
1947	6.8	20.6	12.8	38.8	8.8	26.7	4.3	13.0	.3	0.9	33.0
1948	7.1	20.9	12.3	36.3	8.8	26.0	4.7	13.9	1.0	3.0	33.9
1949	6.9	21.9	11.4	36.2	8.1	25.7	4.6	14.6	.5	1.6	31.5
1950	7.6	22.3	12.3	36.2	8.6	25.3	5.0	14.7	.5	1.5	34.0
1951	7.9	21.5	13.7	37.2	9.2	25.0	5.3	14.4	.7	1.9	36.8
1952	8.0	21.9	13.1	35.9	9.2	25.2	5.5	15.1	.7	1.9	36.5
1953	7.8	20.7	13.8	36.7	9.2	24.5	5.9	15.7	.9	2.4	37.6
1954	8.0	22.1	12.5	34.4	9.1	25.1	6.0	16.5	.7	1.9	36.3
1955	8.6	21.7	14.1	35.5	9.8	24.7	6.6	16.6	.6	1.5	39.7
1956	9.0	21.6	14.6	35.0	10.1	24.2	7.1	17.0	.9	2.2	41.7
1957	8.7	20.9	14.5	34.8	10.2	24.4	7.3	17.5	1.0	2.4	41.7
1958	9.5	22.8	13.5	32.4	10.3	24.7	7.3	17.5	1.1	2.6	41.7
1959	9.7	22.5	14.0	32.5	10.4	24.1	7.9	18.3	1.1	2.6	43.1
1960	10.2	22.9	14.6	32.7	10.8	24.2	8.3	18.6	.7	1.6	44.6
1961	10.4	22.9	14.6	32.2	11.0	24.3	8.5	18.8	.8	1.8	45.3
1962	10.9	23.0	15.3	32.3	11.4	24.0	9.1	19.2	.7	1.5	47.4
1963	11.0	22.3	15.9	32.3	12.0	24.3	9.7	19.7	.7	1.4	49.3
1964	11.1	21.7	16.7	32.6	12.2	23.8	10.4	20.3	.8	1.6	51.2
1965	11.8	22.2	17.2	32.3	12.7	23.8	11.1	20.8	.5	0.9	53.3
1966	12.4	22.0	18.0	31.9	13.3	23.6	12.1	21.4	.6	1.1	56.4
1967	13.0	22.3	18.3	31.4	14.0	24.0	12.7	21.8	.3	0.5	58.3
1968	13.1	21.2	19.4	31.4	15.2	24.6	13.9	22.5	.2	0.3	61.8
1969	13.6	20.9	20.1	30.9	15.8	24.3	15.3	23.6	.2	0.3	65.0
1970	14.0	20.8	20.4	30.3	16.3	24.2	16.5	24.4	.2	0.3	67.4
1971	14.2	20.7	20.0	29.1	17.1	24.9	17.2	25.0	.2	0.3	68.7
1972	14.7	20.4	20.6	28.6	18.1	25.1	18.6	25.8	.1	0.1	72.1
1973 p/	15.4	20.4	21.4	28.3	18.7	24.7	19.8	26.2	.3	0.4	75.6

p/ Preliminary

1/ Gross energy is that contained in all types of commercial energy at the time it is incorporated in the economy, whether the energy is produced domestically or imported. Gross energy comprises inputs of primary fuels (or their derivatives), and outputs of hydropower and nuclear power converted to theoretical energy inputs. Gross energy includes the energy used for the production, processing, and transportation of energy proper.

Table 3.-United States total net consumption of energy resources by consuming sectors (1947-1973)

Year	Household & Commercial		Industrial		Transportation		Net energy inputs
	Quadrillion Btu	% of total	Quadrillion Btu	% of total	Quadrillion Btu	% of total	
1947	7.1	24.4	13.3	45.4	8.8	30.2	29.2
1948	7.5	25.7	12.8	44.0	8.8	30.3	29.1
1949	7.4	27.0	11.8	43.4	8.1	29.6	27.3
1950	8.1	27.4	12.9	43.5	8.6	29.1	29.6
1951	8.5	26.4	14.4	44.8	9.2	28.8	32.1
1952	8.6	27.3	13.8	43.6	9.2	29.1	31.6
1953	8.5	26.3	14.6	45.1	9.2	28.6	32.3
1954	8.8	28.1	13.3	42.7	9.1	29.2	31.2
1955	9.4	27.5	15.1	43.9	9.8	28.6	34.4
1956	9.9	27.7	15.7	43.9	10.1	28.4	35.8
1957	9.7	27.3	15.6	43.9	10.2	28.8	35.6
1958	10.6	29.8	14.6	41.2	10.3	29.0	35.5
1959	10.9	29.8	15.3	41.7	10.4	28.5	36.6
1960	11.4	29.9	15.9	41.7	10.8	28.4	38.1
1961	11.8	30.4	15.9	41.2	11.0	28.4	38.7
1962	12.4	30.7	16.7	41.1	11.4	28.2	40.5
1963	12.7	30.1	17.4	41.4	12.0	28.5	42.1
1964	12.9	29.8	18.2	42.0	12.3	28.2	43.4
1965	13.8	30.4	18.8	41.5	12.7	28.1	45.3
1966	14.5	30.4	19.8	41.6	13.4	28.0	47.7
1967	15.4	30.9	20.1	40.7	14.0	28.4	49.4
1968	15.6	29.9	21.4	41.0	15.2	29.1	52.2
1969	16.4	30.1	22.3	40.9	15.8	29.0	54.5
1970	17.0	30.3	22.6	40.5	16.4	29.2	56.0
1971	17.4	30.7	22.3	39.3	17.1	30.0	56.8
1972	18.2	30.6	23.2	39.0	18.1	30.4	59.5
1973 p/	19.1	30.7	24.3	39.1	18.8	30.2	62.2

p/ Preliminary

Table 4.-United States total gross consumption of energy resources by major sources[1/]
(1947- 1973)

Year	Coal		Petroleum		Natural gas (dry)		Hydropower		Nuclear power		Total Gross Energy Inputs
	Quadrillion Btu	Percent of Total	Quadrillion Btu	Percent of Total	Quadrillion Btu	Percent of Total	Quadrillion Btu	Percent of Total	Quadrillion Btu	Percent of Total	
1947	15.8	47.9	11.4	34.6	4.5	13.6	1.3	3.9	-	-	33.0
1948	14.9	44.0	12.6	37.2	5.0	14.7	1.4	4.1	-	-	33.9
1949	12.6	40.0	12.1	38.4	5.3	16.8	1.5	4.8	-	-	31.5
1950	12.9	38.0	13.5	39.7	6.2	18.2	1.4	4.1	-	-	34.0
1951	13.2	35.9	14.9	40.5	7.2	19.5	1.5	4.1	-	-	36.8
1952	11.9	32.6	15.3	41.9	7.8	21.4	1.5	4.1	-	-	36.5
1953	11.9	31.7	16.1	42.8	8.2	21.8	1.4	3.7	-	-	37.6
1954	10.2	28.1	16.1	44.3	8.6	23.7	1.4	3.9	-	-	36.3
1955	11.6	29.2	17.5	44.1	9.2	23.2	1.4	3.5	-	-	39.7
1956	11.8	28.3	18.6	44.6	9.8	23.5	1.5	3.6	-	-	41.7
1957	11.2	26.9	18.6	44.6	10.4	24.9	1.5	3.6	Neg.	Neg.	41.7
1958	9.9	23.7	19.2	46.1	11.0	26.4	1.6	3.8	Neg.	Neg.	41.7
1959	9.8	22.7	19.7	45.7	12.0	27.9	1.6	3.7	Neg.	Neg.	43.1
1960	10.1	22.6	20.1	45.1	12.7	28.5	1.7	3.8	Neg.	Neg.	44.6
1961	9.9	21.9	20.5	45.3	13.2	29.1	1.7	3.7	Neg.	Neg.	45.3
1962	10.2	21.5	21.3	44.9	14.1	29.8	1.8	3.8	Neg.	Neg.	47.4
1963	10.7	21.7	22.0	44.6	14.8	30.0	1.8	3.7	Neg.	Neg.	49.3
1964	11.3	22.1	22.4	43.7	15.6	30.5	1.9	3.7	Neg.	Neg.	51.2
1965	11.9	22.4	23.2	43.5	16.1	30.2	2.1	3.9	Neg.	Neg.	53.3
1966	12.5	22.2	24.4	43.3	17.4	30.8	2.0	3.5	0.1	0.2	56.4
1967	12.3	21.1	25.3	43.4	18.3	31.4	2.3	3.9	0.1	0.2	58.3
1968	12.7	20.5	27.1	43.9	19.6	31.7	2.3	3.7	0.1	0.2	61.8
1969	12.7	19.5	28.4	43.7	21.0	32.3	2.7	4.2	0.2	0.3	65.0
1970	13.0	19.3	29.6	43.9	22.0	32.6	2.6	3.9	0.2	0.3	67.4
1971	12.1	17.6	30.6	44.5	22.8	33.2	2.8	4.1	0.4	0.6	68.7
1972	12.5	17.3	33.0	45.8	23.1	32.1	2.9	4.0	0.6	0.8	72.1
1973 p/	13.5	17.9	34.7	45.9	23.6	31.2	2.9	3.8	.9	1.2	75.6

[1/] Gross energy is that contained in all types of commercial energy at the time it is incorporated in the economy, whether the energy is produced domestically or imported. Gross energy comprises inputs of primary fuels (or their derivatives); and outputs of hydropower and nuclear power converted to theoretical energy inputs. Gross energy includes the energy used for the production, processing, and transportation of energy proper.

Neg. Negligible

p/ Preliminary

Table 5. -Selected United States Economic and Energy Indicators; Actual for 1973 and Projected to the Year 2000

	1973	1975	1980	1985	2000
Gross Energy Inputs (Quadrillion Btu) 1/	75.6	74.8	95.5	116.0	191.9
Net Energy Inputs (Quadrillion Btu) 2/	62.2	64.4	75.9	89.4	139.4
Population (Million)	211.0	216.2	229.4	243.3	279.7
Gross National Product (Millions of 1958 dollars)	841.3	891	1,102	1,343	2,438
Energy/GNP Ratio (Thousands of Btu per 1958 dollars)	89.8	88.5	86.7	86.4	78.7
Gross Energy/Capita Ratio (Millions of Btu)	358.1	369.1	416.3	476.8	686.1
Net Energy/Capita Ratio (Millions of Btu)	294.7	297.9	330.8	367.4	498.4
Efficiency Factor (Percent) 3/	82.3	80.7	79.5	77.0	72.6

1/ Gross energy inputs refers to the total energy inputs to all sectors.

2/ Net energy inputs refers to the direct energy going to the Industrial, Transportation, and Household and Commercial sectors plus electrical energy converted on the basis of 3,412 Btu/kwhr.

3/ Refers to the overall efficiency of conversion of gross energy to the form used by the final consuming sectors. Equal to net energy/gross energy.

Source: Based on "U.S. Energy Through the Year 2000," Dept. of Interior, Dec. 1972

Revised 1/25/74

Table 6 . Direct energy consumption by sector (quadrillion Btu)

Sector	1/ 1973	Percent	1975	Percent	1980	Percent	1985	Percent	2000	Per
Household and Commercial -------	15.4	20.4	15.9	19.8	17.5	18.2	19.0	16.3	21.9	11
Industrial---------------------	21.7	28.7	22.8	28.5	24.9	25.9	27.6	23.6	39.3	20
Transportation-----------------	18.7	24.7	19.0	23.8	22.8	23.8	27.0	23.2	42.6	22
Electrical Generation----------	19.8	26.2	21.9	27.9	29.5	31.2	39.8	34.6	80.4	41
Synthetic Gas------------------	-	-	-	-	0.9	0.9	2.7	2.3	7.7	4
Total--------------------	75.6	100.0	79.8	100.0	95.5	100.0	116.0	100.0	191.9	100

1/ Preliminary - Miscellaneous consumption (.3 quadrillion Btu) included in Industrial Sector

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Table 7 . Net Energy to final consuming sector (quadrillion Btu)

Sector	1/ 1973	Percent	1975	Percent	1980	Percent	1985	Percent	2000	Per
Household and Commercial-------	19.1	30.7	20.2	31.0	23.9	31.4	27.7	30.9	39.6	28.
Industrial---------------------	24.3	39.1	25.9	39.8	29.4	38.6	34.9	38.9	57.8	41.
Transportation-----------------	18.8	30.2	19.1	29.3	22.9	30.1	27.1	30.2	42.7	30.
Total-------------------	62.2	100.0	65.1	100.0	76.2	100.0	89.7	100.0	140.1	100.

1/ Preliminary

Table 8 .-United States Total gross consumption of energy resources by major sources, 1973 preliminary and projected to year 2000

	1973	1975	1980	1985	2000
Petroleum products 1/					
Million bbl---------------------	6,296	6,490	7,855	9,345	12,985
Million bbl/day-----------------	17.2	17.8	21.6	25.6	35.6
Trillion Btu--------------------	34,689	35,910	43,530	51,840	71,380
Percent of total gross inputs 3/	45.9	45.0	45.6	44.7	37.2
Natural Gas					
Billion cu.ft.------------------	22,850	23,672	24,869	26,437	32,959
Trillion Btu--------------------	23,558	24,400	25,640	27,250	33,980
Percent of total gross inputs---	31.2	30.6	26.8	23.5	17.7
Coal 3/					
Million short tons--------------	569	565	665	893	1,310
Trillion Btu--------------------	13,519	13,830	16,140	21,470	31,360
Percent of total gross inputs---	17.9	17.3	16.9	18.5	16.3
Hydropower					
Million kwhrs-------------------	280	285	313	339	394
Trillion Btu--------------------	2,941	2,910	2,970	3,120	3,350
Percent of total gross inputs---	3.9	3.6	3.1	2.7	1.7
Nuclear Power					
Billion kwhr--------------------	80	245	651	1,130	5,466
Trillion Btu--------------------	853	2,610	6,940	11,750	49,200
Percent of total gross inputs---	1.1	3.3	7.3	10.1	25.6
Geothermal					
Billion kwhr--------------------	4/	4	14	28	121
Trillion Btu--------------------	4/	90	300	610	2,630
Percent of total gross inputs---	-	0.1	0.3	0.5	1.4
Total Gross Energy Inputs					
Trillion Btu--------------------	75,561	79,750	95,520	116,040	191,900

1/ Includes crude oil, shale oil, and natural gas liquids
2/ Percentage may not add to 100 due to rounding
3/ Includes bituminous, lignite, and anthracite, does not include export demand
4/ Included in hydropower.

Table 9. United States total gross consumption of energy resources by major sources and consuming sectors, 1973 preliminary, and projected to the year 2000
(in standard physical units) 1/

	Consuming Sector	Coal	Petroleum	Natural Gas	Nuclear Power	Hydropower	Geothermal	Synthetic Gas Distributed	Utility Electricity Distributed
1973	Household & Commercial-----	14.0	1,228.6	7,760.0	-	-	-	-	1,092.2
	Industrial-----------------	166.3	1,178.2	10,500.0	-	-	-	-	782.8
	Transportation-------------	0.2	3,336.6	790.0	-	-	-	-	5.3
	Electrical generation------	388.4	552.1	3,800.0	80	280	3/	-	-
	Synthetic gas--------------	-	-	-	-	-	-	-	-
	Total----------------	568.9	6,295.5	22,850.0	80	280	-	-	1,880.3
1975	Household & Commercial-----	12	1,221	8,400	-	-	-	-	1,210
	Industrial-----------------	169	1,336	10,626	-	-	-	-	858
	Transportation-------------	-	3,360	960	-	-	-	-	6
	Electrical generation------	384	573	3,686	245	285	4	-	-
	Synthetic gas--------------	-	-	-	-	-	-	-	-
	Total----------------	565	6,490	23,672	245	285	4	-	2,074
1980	Household & Commercial-----	11	1,356	9,195	-	-	-	320	1,728
	Industrial-----------------	175	1,623	10,892	-	-	-	380	1,191
	Transportation-------------	-	3,992	1,290	-	-	-	-	9
	Electrical generation------	460	800	3,492	651	313	14	-	-
	Synthetic gas--------------	19	84	-	-	-	-	-	-
	Total	665	7,855	24,869	651	313	14	700	2,928
1985	Household & Commercial-----	4	1,546	9,758	-	-	-	940	2,229
	Industrial-----------------	190	1,868	11,805	-	-	-	1,060	1,797
	Transportation-------------	-	4,739	1,528	-	-	-	-	11
	Electrical generation------	613	1,064	3,346	1,130	339	28	-	-
	Synthetic gas--------------	86	128	-	-	-	-	-	-
	Total----------------	893	9,345	26,437	1,130	339	28	2,000	4,037
2000	Household & Commercial-----	-	1,953	10,475	-	-	-	2,640	4,324
	Industrial-----------------	247	2,670	17,401	-	-	-	2,860	4,482
	Transportation-------------	-	7,450	2,522	-	-	-	-	15
	Electrical generation------	755	807	2,561	5,466	394	121	-	-
	Synthetic gas--------------	308	105	-	-	-	-	-	-
	Total----------------	1,310	12,985	32,959	5,466	394	121	5,500	8,821

1/ Coal-- million short tons
Petroleum--million barrels
Natural and Synthetic gas--billion cubic feet
Nuclear, hydropower, geothermal, and utility electricity--billion kilowatt hours
2/ Includes net imports of electricity
3/ Included in hydropower

Table 10. United States total gross consumption of energy resources by major sources and consuming sectors
1973 preliminary, and projected to the year 2000
(in trillion Btu)

Consuming Sector	Coal	Petroleum	Natural Gas	Total Fossil Fuels	Nuclear Power	Hydropower	Geothermal power	Total Gross Energy Inputs	Synthetic Gas Distributed	Total Four Sector Inputs	Utility Electricity Distributed	Total Three Sector Inputs
1973 (preliminary)												
Household & Commercial---	370	7,024	8,001	15,395	--	--	--	15,395	--	15,395	3,727	19,122
Industrial---------------	4,454	6,303	10,825	21,582	--	--	--	21,617	--	24,617	2,671	24,288
Transportation-----------	5	17,927	814	18,746	--	--	--	18,746	--	18,746	18	18,764
Electrical generation----	8,691	3,435	3,918	16,044	853	2,941	(in hydro)	19,803	--	19,803	--	--
Synthetic gas------------	--	--	--	--	--	--	--	--	--	--	--	--
Total----------------	13,520	34,689	23,558	71,767	853	2,941	--	75,561	--	75,561	6,416	62,174
1975												
Household & Commercial---	330	6,950	8,660	15,940	--	--	--	15,940	--	15,940	4,130	20,070
Industrial---------------	4,600	7,330	10,950	22,880	--	--	--	22,880	--	22,880	2,930	25,810
Transportation-----------	--	18,050	990	19,040	--	--	--	19,040	--	19,040	20	19,060
Electrical generation----	8,900	3,580	3,800	16,280	2,610	2,910	90	21,890	--	21,890	--	--
Synthetic gas------------	--	--	--	--	--	--	--	--	--	--	--	--
Total----------------	13,830	35,910	24,400	74,140	2,610	2,910	90	79,750	--	79,750	7,080	64,940
1980												
Household & Commercial---	300	7,720	9,480	17,500	--	--	--	17,500	320	17,820	5,900	23,720
Industrial---------------	4,750	8,930	11,230	24,910	--	--	--	24,910	380	25,290	4,060	29,350
Transportation-----------	--	21,440	1,330	22,770	--	--	--	22,770	--	22,770	30	22,800
Electrical generation----	10,660	5,000	3,600	19,260	6,940	2,970	300	29,470	--	29,470	--	--
Synthetic gas------------	430	440	--	870	--	--	--	870	--	--	--	--
Total----------------	16,140	43,530	25,640	85,310	6,940	2,970	300	95,520	700	94,650	9,990	75,870
1985												
Household & Commercial---	100	8,800	10,060	18,960	--	--	--	18,960	940	19,900	7,610	27,510
Industrial---------------	5,150	10,270	12,160	27,580	--	--	--	27,580	1,060	28,640	6,130	34,770
Transportation-----------	--	25,450	1,580	27,030	--	--	--	27,030	--	27,030	40	27,070
Electrical generation----	14,220	6,650	3,450	24,320	11,750	3,120	610	39,800	--	39,800	--	--
Synthetic gas------------	2,000	670	--	2,670	--	--	--	2,670	--	--	--	--
Total----------------	21,470	51,840	27,250	100,560	11,750	3,120	610	116,040	2,000	113,370	13,780	89,350
2000												
Household & Commercial---	--	11,120	10,800	21,920	--	--	--	21,920	2,640	24,560	14,750	39,310
Industrial---------------	6,700	14,660	17,940	39,300	--	--	--	39,300	2,860	42,160	15,920	57,450
Transportation-----------	--	40,010	2,600	42,610	--	--	--	42,610	--	42,610	50	42,660
Electrical generation----	17,520	5,040	2,640	25,200	49,200	3,350	2,630	80,380	--	83,380	--	--
Synthetic gas------------	7,140	550	--	7,690	--	--	--	7,690	--	--	--	--
Total----------------	36,360	71,380	33,980	136,720	49,200	3,350	2,630	191,900	5,500	183,210	30,690	139,420

1/ The sum of the "three sector inputs" is equal to net energy consumption.

Table 11. United States Potential Gross Production of Energy Resources by Major Sources, 1973 Actual, and Projected to the Year 2000

	1973	1975	1980	1985	2000
Petroleum 1/					
Million barrels----------------------------	4,136	3,767	4,157	4,000	3,566
Million bbl/day---------------------------	11.3	10.3	11.4	11.0	9.8
Trillion Btu------------------------------	22,165	20,800	22,950	22,080	19,680
Percent of total gross production -------	35.3	32.2	30.9	26.2	14.1
Natural gas, dry					
Billion cubic feet------------------------	21,820	21,962	22,269	21,837	22,159
Trillion Btu------------------------------	22,496	22,640	22,960	22,510	22,850
Percent of total gross production--------	35.8	35.1	30.9	26.7	16.3
Coal 2/					
Million short tons------------------------	596.5	636	740	980	1,418
Trillion Btu------------------------------	14,355	15,450	17,980	23,810	34,460
Percent of total gross production--------	22.9	24.0	24.2	28.2	24.6
Shale Oil					
Million bbl-------------------------------	-	-	18	91	767
Million bbl/day---------------------------	-	-	.05	.25	2.1
Trillion Btu------------------------------	-	-	100	500	4,230
Percent of total gross production--------	0	0	0.1	0.6	3.0
Geothermal					
Billion Kwhrs-----------------------------	(in hydro)	4	14	28	280
Trillion Btu------------------------------	(in hydro)	90	300	610	6,080
Percent of total gross production--------	0	0.1	0.4	0.7	4.3
Solar					
Trillion Btu------------------------------	-	-	-	insig.	100
Percent of total gross production--------	0	0	0	0	0.1
Hydropower					
Billion Kwhrs-----------------------------	283.4	285	313	339	394
Trillion Btu------------------------------	2,941	2,910	2,970	3,120	3,350
Percent of total gross production--------	4.7	4.5	4.0	3.7	2.4
Nuclear Power					
Billion Kwhrs-----------------------------	80	245	651	1,130	5,466
Trillion Btu------------------------------	853	2,610	6,940	11,750	49,200
Percent of total gross production--------	1.4	4.0	9.4	13.9	35.2
Total Potential Gross Domestic Production					
Trillion Btu------------------------------	62,810	64,500	74,200	84,380	139,950

1/ Includes natural gas liquids and crude petroleum.
2/ Includes anthracite,bituminous and lignite coals.

Table 12. **Estimated Gaseous Fuel Supply Schedule, 1973 Preliminary, and Projected to the Year 2000**

	1973 p	1975	1980	1985	2000
Total Supply:					
Billion cubic feet	22,850	23,672	25,569	28,437	38,459
Trillion Btu	23,558	24,400	26,340	29,250	39,480
Domestic Supply:					
Domestic Natural Gas					
Billion cubic feet	21,820	21,962	22,269	21,837	22,159
Trillion Btu	22,496	22,640	22,960	22,510	22,850
Synthetic Gas					
Billion cubic feet	-	-	700	2,000	5,500
Trillion Btu	-	-	700	2,000	5,500
Total Domestic Supply					
Billion cubic feet	21,820	21,962	22,969	23,837	27,659
Trillion Btu	22,496	22,640	23,660	24,510	28,350
Gas Imports:					
Pipeline Imports					
Billion cubic feet	1,030	1,210	1,700	2,400	7,000
Trillion Btu	1,062	1,240	1,750	2,470	7,210
Liquefied Natural Gas					
Billion cubic feet	-	500	900	2,200	3,800
Trillion Btu	-	520	930	2,270	3,920
Total Imports					
Billion cubic feet	1,030	1,710	2,600	4,600	10,800
Trillion Btu	1,062	1,760	2,680	4,740	11,130
Percent of total supply	4.5	7.2	10.2	16.2	28.2

Table 13. Estimated Petroleum Supply Schedule, 1973 Actual With Projections to the Year 2000 1/

	1973	1975	1980	1985	2000
Total Supply:					
Million bbl	6,295	6,490	7,855	9,345	12,985
Trillion Btu	34,689	35,910	43,530	51,840	71,380
Million bbl/day	17.2	17.8	21.5	25.6	35.6
Domestic Supply:					
Lower 48					
Million bbl	4,136	3,767	3,427	3,270	2,945
Trillion Btu	22,165	20,800	18,920	18,050	16,250
Million bbl/day	11.3	10.3	9.4	9.0	8.1
Alaskan North Slope					
Million bbl	-	-	730	730	621
Trillion Btu	-	-	4,030	4,030	3,430
Million bbl/day	-	-	2.0	2.0	1.7
Synthetic Liquids 2/					
Million bbl	-	-	18	91	767
Trillion Btu	-	-	100	500	4,230
Million bbl/day	-	-	.05	.25	2.1
Total Potential Supply:					
Million bbl	4,136	3,767	4,175	4,091	4,333
Trillion Btu	22,165	20,800	23,050	22,580	23,910
Million bbl/day	11.3	10.3	11.4	11.2	11.9
Supplemental Supplies 3/					
Million bbl	4/2,159	4/ 2,723	4/ 3,680	5,254	8,652
Trillion Btu	12,524	15,110	20,480	29,260	47,470
Million bbl/day	5.9	7.5	10.1	14.4	23.7
Percent of total Supply	34.3	42.0	46.8	56.2	66.6

1/ Based on continuations of present trends. Represents a reevaluation of supply forecasts in U.S. Energy Through the Year 2000.

2/ Includes natural gas liquids.

3/ May be from imports, shale oil, coal liquefaction, etc.

4/ All imports.

APPENDIX III-B.

ENERGY CONSERVATION TABLES

Table 1.-End use energy consumption in the United States, 1970 [1]

	Direct		Purchased electrical energy		Total	
	Trillion Btu	Percent of total	Trillion Btu	Percent of total	Trillion Btu	Percent of total
Residential						
Space heating	6,341	12.3	246	.5	6,587	12.7
Water heating	1,176	2.3	238	.4	1,414	2.7
Cooking	354	.7	101	.2	455	.9
Clothes drying	86	.2	60	.1	146	.3
Refrigeration	9	-	292	.6	301	.6
Air conditioning	8	-	201	.4	209	.4
Other	-	-	494	.9	494	.9
Total	7,974	15.3	1,632	3.1	9,606	18.4
Commercial						
Space heating	4,261	8.2	-	-	4,261	8.2
Water heating	419	.8	86	.2	505	1.0
Cooking	118	.2	8	-	126	0.2
Refrigeration	-	-	253	.5	253	.5
Air conditioning	134	.3	423	.8	557	1.1
Other	-	-	598	1.1	598	1.1
Total	4,932	9.5	1,368	2.6	6,300	12.1
Industrial						
Process heat	10,514	20.2	-	-	10,514	20.2
Electric drive	-	-	1,764	3.4	1,764	3.4
Electrolytic process	-	-	254	.5	254	.5
Direct heat	6,721	12.9	119	.2	6,840	3.1
Other	-	-	73	.1	73	.1
Total	17,235	33.1	2,210	4.3	19,445	37.4
Transportation						
Fuel	16,345	31.4	16	-	16,361	31.4
Total	16,345	31.4	16	-	16,361	31.4
TOTAL [2]	46,831	90.9	5,226	10.0	52,057	100.0

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[1] Includes only the Household and Commercial, Industrial, and Transportation Sectors.
[2] 214 trillion Btu miscellaneous and unaccounted for.

Table 2. Net Energy Conservation by Sector and Source 1975-2000,

Energy Savings	Coal		Petroleum			Natural Gas		Electricity		Total Savings
	Mil. tns.	Tril.Btu	Mil.bbl	Tril. Btu	Mil. bbl/day	Bil.cu. ft.	Tril.Btu	Bil.Kwhr.	Tril. Btu	Tri. Btu
1975										
Household & Commercial	-	-	-	-		-	-	-	-	-
Industrial	17	420	49	270	0.1	776	800	3	10	1,500
Transportation	-	-	159	880	0.4	-	-	-	-	880
Total	17	420	208	1,150	0.6	776	800	3	10	2,380
1980										
Household & Commercial	-	-	7	40	insig	48	50	9	30	120
Industrial	14	350	103	570	0.3	1,639	1,690	3	10	2,620
Transportation	-	-	408	2,250	1.1	-	-	-	-	2,250
Total	14	350	518	2,860	1.4	1,687	1,740	12	40	4,990
1985										
Household & Commercial	-	-	18	100	insig	145	150	29	100	350
Industrial	61	1,480	178	980	0.5	2,764	2,850	6	20	5,330
Transportation	-	-	799	4,410	2.2	-	-	-	-	4,410
Total	61	1,480	995	5,490	2.7	2,909	3,000	35	120	10,090
2000										
Household & Commercial	-	-	203	1,120	0.6	951	980	108	370	2,470
Industrial	117	2,840	333	1,840	0.9	5,393	5,560	322	1,100	11,340
Transportation	-	-	1,607	8,870	4.4	-	-	-	-	8,870
Total	117	2,840	2,143	11,830	5.9	6,344	6,540	430	1,470	22,680

note: digits may not add to totals due to random rounding.

Table 3. Petroleum Consumption in the Household &Commercial, Industrial, and Transportation Sectors 1975-2000 (with and without energy conservation)

	Base Consumption		Potential Conservation		Consumption w/ conserv	
	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillio Btu
1975						
Household & Commercial	1,221	6,950	-	-	1,221	6,950
Industrial	1,336	7,330	49	270	1,287	7,060
Transportation	3,360	18,050	159	880	3,201	17,170
Total	5,917	32,330	208	1,150	5,709	31,180
1980						
Household & Commercial	1,356	7,720	7	40	1,349	7,680
Industrial	1,623	8,930	103	570	1,520	8,360
Transportation	3,992	21,440	408	2,250	3,584	19,190
Total	6,971	38,090	518	2,860	6,453	35,230
1985						
Household & Commercial	1,546	8,800	18	100	1,528	8,700
Industrial	1,868	10,270	178	980	1,690	9,290
Transportation	4,739	25,450	799	4,410	3,940	21,040
Total	8,153	44,520	995	5,490	7,158	39,030
2000						
Household & Commercial	1,953	11,120	203	1,120	1,750	10,000
Industrial	3,670	14,660	333	1,840	2,337	12,820
Transportation	7,450	40,010	1,607	8,870	5,843	31,140
Total	12,073	65,790	2,143	11,830	9,930	53,960

Table 4. Gaseous Fuels Consumption in the Household & Commercial, Industrial, and Transportation Sectors, 1975-2000 (with and without conservation)

	Base Consumption		Potential Conservation		Consumption With Conservation	
	Billion cu. ft.	Trillion Btu	Billion cu. ft.	Trillion Btu	Billion cu. ft.	Trillion Btu
1975						
Household & Commercial	8,400	8,660	-	-	8,400	8,660
Industrial	10,626	10,950	776	800	9,850	10,150
Transportation	960	990	-	-	960	990
Total	19,986	20,600	776	800	19,210	19,800
1980						
Household & Commercial	9,195	9,480	48	50	9,147	9,430
Industrial	10,892	11,230	1,639	1,690	9,253	9,540
Transportation	1,290	1,330	-	-	1,290	1,330
Total	21,377	22,040	1,687	1,740	19,690	20,300
1985						
Household & Commercial	9,758	10,060	145	150	9,613	9,910
Industrial	11,805	12,160	2,764	2,850	9,041	9,310
Transportation	1,528	1,580	-	-	1,528	1,580
Total	23,091	23,800	2,909	3,000	20,182	20,800
2000						
Household & Commercial	10,475	10,800	951	980	9,524	9,820
Industrial	17,401	17,940	5,393	5,560	12,008	12,380
Transportation	2,522	2,600	-	-	2,522	2,600
Total	30,398	31,340	6,344	6,540	24,054	24,800

Table 5. Consumption of Coal in the Household and Commercial, Industrial, and Transportation Sectors 1975-2000 (with and without energy conservation)

	Base Consumption		Conservation		Consumption w/conservation	
	10^6 ton	10^{12} Btu	10^6 ton	10^{12} Btu	10^6 ton	10^{12} Btu
1975						
Household and Commercial------	12	330	-	-	12	330
Industrial-------------------	169	4,600	17	420	152	4,180
Transportation---------------	-	-	-	-	-	-
Total--------------------	181	4,930	17	420	164	4,510
1980						
Household and Commercial------	11	300	-	-	11	300
Industrial-------------------	175	4,750	14	350	161	4,400
Transportation---------------	-	-	-	-	-	-
Total--------------------	186	5,050	14	350	172	4,700
1985						
Household and Commercial------	4	100	-	-	4	100
Industrial-------------------	190	5,150	61	1,480	129	3,670
Transportation---------------	-	-	-	-	-	-
Total--------------------	194	5,250	61	1,480	133	3,770
2000						
Household and Commercial------	-	-	-	-	-	-
Industrial-------------------	247	6,700	117	2,840	130	3,860
Transportation---------------	-	-	-	-	-	-
Total--------------------	247	6,700	117	2,840	130	3,860

Table 6. Consumption of Utility Electricity in the Household & Commercial Industrial, & Transportation Sectors - 1975-2000 (with and without energy conservation)

	Base Consumption		Conservation		Consumption w/Conservation	
	Billion Kwhr	Trillion Btu	Billion Kwhr	Trillion Btu	Billion Kwhr	Trillion Btu
1975						
Household & Commercial	1,210	4,130	-	-	1,210	4,130
Industrial	858	2,930	3	10	855	2,920
Transportation	6	20	-	-	6	20
Total	2,074	7,080	3	10	2,071	7,070
1980						
Household & Commercial	1,728	5,900	9	30	1,719	5,870
Industrial	1,191	4,060	3	10	1,188	4,050
Transportation	9	30	-	-	9	30
Total	2,928	9,990	12	40	2,916	9,950
1985						
Household & Commercial	2,229	7,610	29	100	2,200	7,510
Industrial	1,797	6,130	6	20	1,791	6,110
Transportation	11	40	-	-	11	40
Total	4,037	13,780	35	120	4,002	13,660
2000						
Household & Commercial	4,324	14,750	108	370	4,216	14,380
Industrial	4,482	15,290	322	1,100	4,160	14,190
Transportation	15	50	-	-	15	50
Total	8,821	30,090	430	1,470	8,391	28,620

Table 7 -Net Energy Savings by Sector and Type (in percent)
1975 - 2000

			In Percent	
	1975	1980	1985	2000
Household & Commercial				
Air conditioning	0	3.0	9.4	20.2
Space Heating	0	0.7	1.8	13.6
Total HH & C Savings	0	0.5	1.3	6.2
Industrial				
Primary Aluminum	3.4	2.7	4.2	16.5
Iron & Steel	6.6	12.5	18.4	26.2
Processed Heat	7.2	13.2	18.9	29.2
Total Industrial Saving	5.8	8.9	15.3	19.6
Transportation				
Automobile	6.9	14.5	23.1	33.3
Air Transit	0	3.5	9.0	16.7
Bus/Tr/R.R.	3.6	6.3	9.2	16.7
Ship	3.9	6.2	8.8	16.9
Total Transportation Savings	4.6	9.8	16.3	20.8
Net				
Total Savings of Energy all Sector (percent of Net Energy Consumption)	3.7	6.6	11.2	16.2

PART IV.

NORTHERN GREAT PLAINS REGION

COAL GASIFICATION AND COAL LIQUEFACTION

Gasification of Coal from the Northern Great Plains

Opportunities for expanded use of coal from the vast reserves existing in the Northern Great Plain States are now recognized as among the most promising prospects of the last quarter of this century. As the future unfolds, gasification of coal at regional energy development plants is one way by which this harvest of energy can be accomplished with maximum benefits to both the States and the Nation.

In coal, the ratio of hydrogen to carbon is lower than in gaseous hydrocarbons; hence, the conversion of coal to a synthetic gas fuel involves addition of hydrogen, elimination of carbon, or both. The technology of this process has been worked out on a commercial scale and is illustrated by the Lurgi steam-coal-oxygen gasifiers used in Germany, Great Britain, Australia, and South Africa. Here in the United States, only noncaking coals have been usable in the Lurgi process without pretreatment, but substantial research efforts have been directed to development of commercial sized high-pressure coal-suspension type gasifiers which can use caking coals. This and other processes are described in the "Final Report Of The Supply-Technical Advisory Task Force - Synthetic Gas-Coal", prepared for the Federal Power Commission, April 1973.

Estimates indicate that gas yields of 46,600 cubic feet per ton of coal can be obtained using the Lurgi process, while 56,000 cubic feet per ton of coal can be obtained in a suspension-type gasifier.1/

1/ Energy R&D and National Progress (Chapt. IV, pp 137-143; VIII p. 376)

Although it has not been possible, by existing processes, to produce a synthetic pipeline gas at a price level as low as natural gas, recent and prospective price increases of the latter bring competitive production of synthetic gas closer. As the supply of natural gas starts to diminish, coal-to-gas conversion by the conventional methods of making manufactured gas (water gas, carbureted water gas, producer gas, oil gas, and coke oven gas) or by improved processes will be needed to provide gas for home heating and its other established uses.

Under most favorable circumstances, it is anticipated that 6 to 10 years will be required to develop large-scale commercial gasification of coal.[2/] Early in 1971, accelerating the timetable for production of synthetic natural gas from coal was recognized as a matter of more urgent national concern. At that time, development of the technology of coal gasification was described as a major financing problem, with such high costs and uncertain results that it was impractical for any one company, even the larger energy or utility companies, to assume the risks involved.

At hearings held during November 1971, information was collected regarding specific plans of various companies reported as involved with the commercial development of coal gasification plants. Some of the findings are briefly described as a background of the current situation, mid-year 1973. El Paso Gas Company had announced a 250 million cubic feet per day plant using coal as the raw material and

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[2/] Review of Energy Policy Activities of the 92nd Congress, First Session, pp. 76-81.

applying the Lurgi process because it was the only proven gasification process and was suitable for coals they had under lease. By using the Lurgi process, they expected to produce gas with only 400 Btu (without methanization) but planned to blend the product into their natural gas in the pipeline if it proved infeasible to methanize. Thus, El Paso would be in a position to supply some gas to potential customers they would not otherwise be able to serve if they waited for new technology before building their gasification plant. Also, the new plant was expected to provide training of operators and technicians who through experience might be able to improve the process and contribute to the general national efforts in R & D.

In June 1973 it was reported that detailed engineering on the gasification complex proposed by the El Paso Natural Gas Company is scheduled to start this year, and that their first plant is expected to be on stream in early 1977. At the site, available water supply and coal deposits are sufficient to support three gasification plants, each with a capacity to produce 200 to 250 million cubic feet of pipeline quality gas per day.

At the November 1971 hearing, the consortium formed by a pipeline transmission company (Texas Eastern Transmission Co.), a coal mining company (Utah International), and a gas distributor (Pacific Light Service Co.) stated that their economic and technological feasibility study was to be completed in mid-1972 and that, if results were favorable, they expected to have a coal gasification plant operating by 1975. Water was plentiful, they testified, and the plant would use coal from ample reserves of San Juan Basin coal and would anticipate marketing the synthetic gas in southern California. As of that date, the price of the gas to be produced was estimated at about $1 per 1,000 cubic foot.

Construction cost estimates, filed by Transwestern Coal Gasification Company with the Federal Power Commission, have recently been published in an article on synthetic natural gas production from coal.[3/] For a plant with a capacity of 250 million cubic feet per day, operating 30 Lurgi reactors and gasifying 8 million tons of coal per year, the estimated capital expenditure totals just under $406 million. The projected cost of service, also based on the company's FPC filing, is now indicated at $1.298 per 1,000 cubic feet for SNG produced in 1976; $1.302 in 1977; and $1.308 in 1978. These cost of service estimates were arrived at by adding operating and maintenance expenses (adjusted for residual product credits), depreciation, taxes (other than income), and return on total capital investment at a moderate rate of about 10.5 percent.

According to information collected during November 1971, the FMC Corporation was attempting to interest a number of firms in their COGAS process, producing both oil and gas. After oil is removed from the coal, in this process, the residual char is used to produce a high Btu gas by a new proprietary process, and assuming the oil sold at $4 per barrel, the gas price would be 75 cents to 90 cents

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[3/] "SNG From Coal Involves Big Projects," The Oil and Gas Journal, June 25, 1973. pp 131-134.

per million Btu. FMC emphasized the importance of finance charges as a cost element affecting gas production by their new process, illustrating this by two examples: if the average interest rate on plant capital investment was 11 percent, the final gas price would be 82 cents per 1,000 cubic feet; if lowered to 7 percent, the gas price could be reduced to 70 cents per 1,000 cubic feet. At that time, however, no pilot plant operation had established these estimates as firmly based.

A coal gasification group, founded at the request of the Illinois Commerce Commission, was reported to be concentrating on problems of producing clean fuel from the high sulfur coal resources of Illinois. This coal had been found no longer directly usable for generation of electricity until economically practical means are found to extract the sulfur from the coal or remove the sulfur oxides from the flue gases. Recognizing this as a market dislocation affecting both producers and consumers of coal, at a time when the growing shortage of natural gas had become clear, their investigation of conditions relating to production of a clean fuel for use in Illinois generating plants was well justified.

Although some advanced coal gasification technology will be put into operation during the 1976 to 1980 period, it is not expected that gas from coal will contribute major quantities of needed gas until the early 1980's. 4/

4/ Statement of John M. Nassikas, Chairman, FPC, at Hearings before Comm. on Interior & Insular Affairs, April 1972. Fuel and Energy Resources, 1972, Part II, pp. 772-774

As of early 1974, the most substantially funded program of research on coal gasification is that covered by the agreement between the Department of the Interior and the American Gas Association (AGA) providing for $120 million to be spent over a 4-year period. AGA agreed to contribute up to $10 million per year for 4 years beginning in fiscal year 1972 and this is being matched on a 2 to 1 ratio by Federal funds appropriated by Congress. In addition to acceleration of the OCR's three pilot plant operations, additional research is scheduled which is expected to lead to design of a demonstration plant which will be about one-third the size of a commercial conversion plant. [5] In the fourth year of the jointly funded research, the AGA and OCR will jointly determine action on construction of the demonstration plant, holding the option open until further evaluation of their research projects.

Under the research program, sponsored by the American Gas Association, 20,000 tons of coal furnished by U.S. coal companies and utilities has been exported to the British Gas Corporation gasification plant at Westfield, Scotland. There in a unit of the plant set aside for the specific tests, highly caking and swelling coals from various mines will receive extensive testing through use in the Lurgi gasification process.

Experimental coal gasification tests, started by the U.S. Bureau of Mines in October 1972 are expected to develop definite information as to the prospects for Wyoming's low-sulfur coal in use to produce gas with can be marketed within the State and sent by pipelines to meet heating demands of the larger midwest cities. Testing is in coalbeds of about 30 feet thickness and 400 feet underground near Hanna, Wyoming. Holes drilled down to the coal seam are to allow lowering of fluid or chemical explosives which can be set off to fracture the coal. Oxygen will then be injected and the coal ignited so as to give off low Btu (125 to 150 Btu/cu.ft.) gas for collection at the surface. As of mid-1973, the testing continues with further study of the technology of underground gasification, product costs, and product values as the purpose.

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[5] Annual Reports of Office of Coal Research, 1972 and 1973.

At Rapid City, South Dakota, a 35 ton per day pilot plant for lignite gasification has been making tests which may lead to substantially increased use of lignite for that purpose in future years. This would utilize large reserves in the Dakotas and Montana. An engineering and economic study of potential lignite gasification costs had already been completed by January 1965, and the following conclusions appeared in the summary of the report made under "Phase I" of the Consolidation Coal Company contract with the Office of Coal Research: [6]

> Gasification of lignite is technically feasible, and by 1975 this procedure may become economically attractive.
>
> Development of a new source of competitively priced, high Btu gas in the North Central area would stimulate further industrial development of the area, generating new payrolls and local taxes.

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[6] "Pipeline Gas From Lignite Gasification," Report No. 1, Project No. 180, U.S. Dept. of Interior, Office of Coal Research. January 13, 1965.

Economically justified gasification assumes that the raw lignite, representing about one-third of total costs of pipeline gas, must be delivered to the plant site at 10 cents to 11 cents per million Btu. This assumption would limit economic use to lignite delivered at plant site for $1.33 to $1.46 per ton.

Lignite gasification requires substantial quantities of water, but the cost of supplying the needed water would not restrict plant site location, assuming 1 percent of the minimum daily release from the Garrison Dam Reservoir, on the Missouri River, can be counted on for a gas plant having a capacity of 250 million SCF per day and consuming approximately 22,000 acre feet of water per year.

Dolmite, a natural limestone used as a heat carrier in the Consol CO_2 process is abundant in South Dakota and Wyoming.

Assuming lignite costing $1.50 per ton (10.74¢/MMBtu) and plant investment of $74,200,000, the total cost of producing gas in a baseload plant operated at 95 percent capacity was estimated as detailed below:

Raw Lignite	16.9¢/MM	Btu	Product	Gas
Direct Operating	12.6¢/ "	"	"	"
Capital Charges	10.2¢/ "	"	"	"
Total cost	39.7¢/ "	"	"	"

Transmission costs of 4.3 cents to 8.6 cents/MM Btu were estimated as required to deliver the gas from lignite gasification into the main pipeline network servicing the market area of 5 States (Iowa, Minnesota, Nebraska, North Dakota, and South Dakota)

To produce 8.5 million tons of lignite annually for a 250 MSCF gasification plant, total manpower to operate the mine and necessary subsidiary functions was estimated at 182 union plus 31 salaried employees.[7/]

Production of pipeline gas by gasification of lignite can be practical only if the total cost is competitive with natural gas deliverable to the same customers. In turn, a large gasification plant requires an assured supply of 8.5 million tons annually of very

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7/ "Appendix - Pipeline Gas From Lignite Gasification..." Report No 1 Project No. 180, (Table V, Page 14) low cost lignite which is attainable only from extremely high productivity mines with seams 15 to 20 feet thickness and overburden less than 130 feet. Dedicated tonnage should meet these qualifications and be sufficient to provide the 170 million to 255 million tons total needed to support gasification plant operations over the entire period of its amortization.

Currently, the recognized necessity of such tonnage dedications is illustrated by commercial contracts making such commitments. Only three examples are cited below.

Peabody Coal Company recently announced plans for joint development of a coal mining and gasification project with the Northern Natural Gas Co. of Omaha and the Cities Service Co. of Oklahoma City. [8] The two gas companies have expressed their intentions of building as many as four coal gasification plants, each with 250 million cubic feet per day capacity, in the Powder River Region located in southeastern Montana and northeastern Wyoming. Peabody's dedication of coal tonnage will total about 500 million tons of reserves held on the Northern Cheyenne Indian Reservation, and this will be sufficient to supply two of the proposed gasification plants by production of 8 million tons annually.

In early 1973, the North American Coal Corp. and the Michigan Wisconsin Pipe Line Company (a subsidiary of the American Natural Gas Co.) announced that they were expanding a previously agreed contract for dedication of 1.5 billion tons of lignite for future gasification.

8/ Coal Mining and Processing, May 1973

The original agreement was for a term of 15 years, but it has now been extended through December 1, 1993 and increased the total dedication to nearly 3 billion tons -- a quantity which is adequate to support production of 3 billion cubic feet of gas daily for 25 years. [8]

A more recent announcement apparently has the same basis. Zeigler Coal Company, reported to own or control more than one billion tons of of coal reserves, is being acquired through exchange of stocks by the Houston Natural Gas Corporation. [9]

Looking to the future's opportunities to expand mining and use of coal from the Northern Great Plain States a new concept, "Regional Energy Resource Development Plants," is now receiving attention by both Government and commercial interests involved in the pilot-plant testing of gasification processes.[10] Although the practical economics of the several gasification processes have not yet been satisfactorily resolved, there is a confident expectation that operation of pilot and demonstration plants will develop engineering and cost information which will support subsequent construction of commercial coal gasification plants.

By closely related processes, coal can be converted to both gas and oil. A coal gasification process produces some oil, and coal liquefaction produces some gas. From these facts the concept of a coal-oil-gas (C O G) refinery has evolved. The C O G coal conversion facility would produce solvent refined coal, clean liquid fuels, low B.t.u. gas and generate electricity.

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[8] Coal Mining and Processing, May 1973.

[9] Wall Street Journal, July 10, 1973.

[10] "The Role of Mining in Coal Conversion Complexes," remarks of Dr. George R. Hill (delivered by Mr. Wayne McCurdy) to the Denver Coal Club, Denver, Colorado, on May 14, 1973.

The initial steps in the implementation of this concept are being taken. In the "R & D Report No. 82," prepared for the Office of Coal Research by the Ralph M. Parsons Co. late in 1973, the preliminary design and capital cost estimates for a demonstration plant have been set forth. Such a plant would process 10,000 tons of coal per day. The resulting products would be 1,440 tons of liquid boiler fuel (0.2% sulfur); 2,920 tons of heavy liquid boiler fuel (0.5% sulfur); 2,260 tons of solvent refined coal; 270 tons of naphtha; and 320 tons of sulfur. It was estimated that the fixed capital investment for such a demonstration facility would total $270 million.

A Regional Energy Resource Development Plant would employ a wide variety of processes, including extraction, separation gasification, hydrogenation, purification, processing, and power generation. Related to what we have known in past years, the plant's raw material use and resulting production can only be described as "enormous" "gigantic," or "colossal."

A single regional plant would use more than 27 million tons of coal annually. Daily consumption would total 75,000 tons of coal, 32,000 tons of air, and 15 million gallons of water.

Resulting products of each day's operation would include 24 million kilowatt hours of electric energy, 250 to 300 million cubic feet of pipeline gas, 20,000 tons of ashless low-sulfur coal, 75,000 barrels of synthetic oil, 17,000 barrels of butane/propane, 156 tons of organic chemicals for plastic and petrochemical products, 2,200 tons of sulfur, 55,000 barrels of cement, 800 tons of iron, plus cinder building blocks and bricks.

It has been estimated that a commercial coal conversion complex, such as described above, would cost $450 million, and that it would provide up to 2,000 jobs at the mine and plants. From the present pilot up to 2,000 jobs at the mine and plants. From the present pilot plant stage of the gasification program, it is expected that a demonstration plant can be brought into existence by 1976 as the next step toward the more advanced concept.

At this time, the cost elements essential for firm estimates of the future cost of processing and marketing synthetic natural gas cannot be precisely stated. The cost of coal and other raw materials for gasification, the plant investment costs, the capital charges, and the byproduct credits are all items subject to wide variations. However, two tables from an unpublished report of the U.S. Bureau of Mines are attached to make available a summary of recent estimates of the price of synthetic natural gas resulting from two processes applied to both Eastern and Western coals. 11/ (Appendix IV - A1 & 2).

11/ "The Potential Market Availability and Economics of Supplemental Sources of Gaseous Fuels," Vol. I, U.S. Bureau of Mines, unpublished July 1973.

Feedstock costs where using Western subbituminous coals and lignite are estimated to be about one-third less than when using Eastern coals. ($.23 Mcf for Western vs $.36 Mcf for Eastern).

The sensitivity of the selling price of gas to coal prices is illustrated in the second table showing the estimated gas selling price, f.o.b. plants, based on assumed coal costs at three geographical locations. For example, assuming Montana Rosebud seam subbituminous coal costing $2 per ton, the estimated gas selling price is $.83/Mcf; at $4 per ton the gas price increases to $1.24/Mcf. For Illinois No. 6 seam coal costing $4.00 per ton, the estimated gas selling price is $.75/Mcf; at $6.00 per ton the gas price rises to $.89/Mcf; and at $8.00 per ton the gas price f.o.b. plant is $1.03/Mcf.

It is interesting to compare estimates made for the 12,700 Btu coal from the Pittsburgh coal seam. At $4 per ton the estimated gas price is shown as $.67/Mcf; at $6 the price is increased to $.79/Mcf; and at $8 per ton for coal the gas price is estimated at $.90/Mcf. Synthane gasification costs, as estimated in the second table, are lower for the Pittsburgh seam coal for two apparent reasons: (1) due to higher Btu content the tonnage of coal required annually is reduced to about half the tonnage required using Montana subbituminous coal; (2) the initial capital investment is shown to be about 30 percent lower, making possible lower annual capital charges.

In another report dated April 1973 and prepared for the Federal Power Commission, [12] estimated costs of producing gas from coal by the Lurgi process have been compared to estimated costs of conversion by a "Typical New Process". Originally, the estimates were made in 1971 dollars, but by applying escalation factors the following range of costs were derived for 1975, 1980, 1985, and 1990 start-up years:

SUMMARY OF ESTIMATED GAS COSTS FOR LURGI AND TYPICAL NEW PROCESS
(Gas cost in cents per million Btu)

	Deep Mined Bituminous		Surface Mined Subbituminous	
	Lurgi	New Process	Lurgi	New Process
Base Utility Financing				
1975 Start-up	145	125	110	90
1980 "	170	150	130	110
1985 "	200	175	150	125
1990 "	230	200	175	145
Base Private Financing				
1975 Start-up	180	155	140	115
1980 "	215	185	170	140
1985 "	250	215	195	160
1990 "	290	250	230	190

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[12] Final Report, The Supply-Technical Advisory Task Force -- Synthetic Gas-Coal, prepared by Synthetic Gas-Coal Task Force for the Federal Power Commission, April 1973.

The above range of estimated costs varies widely and is to be considered as only a broad indication of the cost of gas produced from coal at plants not yet in opperation -- in fact, not in their completed design. Ongoing research is expected to bring new technology to bear on the conversion processes. Conditions are changing rapidly relative to the alternative energy sources and demands. For these reasons, there is a need for continuing technical evaluation which was recognized in March 1972 by the Office of Coal Research and the American Gas Association joint contract with C.F. Braun & Co. This contract, for which $2,600,000 was allocated, provides for review and audit of research work being performed for A.G.A. and OCR and for engineering of preliminary designs of probable commercial plants to establish a basis for economic comparisons of the alternative conversion processes.

Adoption of the Regional Resource Development Plant concept, modified to fit energy requirements, can offer an opportunity -- through expansion of coal mining -- to maximize use of the Nations most abundant resource in attainment of energy self-sufficiency in United States. Proper planning for such a technological breakthrough is only possible through cooperation of local, State, and national governments plus that of the energy industries and residents in the mining and plant areas.

APPENDIX IV-A.

GASIFICATION ECONOMICS

Appendix IV - A1

Table CSG-1.--Coal Gasification Economics 1/ (approx. 1972 dollars)

	Lurgi	Typical "New Process"
	Eastern Coals	
Total plant investment costs (million dollars) 2/	320	270
Feedstock cost (million dollars/yrs.) 3/	30	30
Other operating cost (million dollars/yr.)	21	15
Capital charge - 15% ($/Mcf)	0.58	0.49
Feedstock costs ($/Mcf)	0.36	0.36
Operations ($/Mcf)	0.25	0.18
Approximate tailgate CSNG price ($/Mcf) 4/	1.19	1.03
	Western Coals	
Total plant investment costs (million dollars) 2/	285	240
Feedstock cost (million dollars/yr.)	19	19
Other operating cost (million dollars/yr.)	22	15
Capital charge 15% ($/Mcf)	0.52	0.44
Feedstock cost ($/Mcf)	0.23	0.23
Operations ($/Mcf)	0.27	0.18
Approximate tailgate CSNG price ($/Mcf) 4/	1.02	0.85

1/ Based in part on data in an unpublished report prepared by the Supply-Technical Advisory Task Force: Synthetic Gas-Coal for the National Gas Survey.

2/ Plant output: 250 million cubic feet per day operating at 90 percent of capacity and 65 percent efficiency. Includes mine preparation costs.

3/ Approximately $6.00 per ton average.

4/ Based on 1,000 Btu/cubic foot.

5/ Approximately $2.50 per ton average.

Appendix IV-A2

Table CSG-3.--Comparison of Synthane gasification costs on different coals

Coal bed	Rosebud[1]	Uncorrelated[1]	Illinois No. 6	Pittsburgh
Process	Synthane[2]	Synthane[2]	Synthane[2]	Synthane[2]
Average Btu value/pound	8,637	8,816	11,700	12,700
Annual production (millions of tons)	8.29	7.44	5.91	4.70
Initial capital investment (million of dollars)	275.52	334.44	212.88	194.61
Annual operating cost based on coal costs		(millions of dollars)		
$2 coal	42.70	37.11	-	-
4 "	51.68	45.18	38.16	42.10
6 "	60.66	53.24	44.56	5 .50
8 "	-	-	50.96	60.90
Gas selling price f.o.b. plant based on coal costs				
$2 "	.83	.72	-	-
4 "	1.04	.90	.75	.67
6 "	1.24	1.08	.89	.79
8 "	-	-	1.03	.90

[1] Montana subbituminous.

[2] Gasification at 1,000 psia followed by shift conversion, purification, and single-stage tube wall methanation

Source: An unpublished report working under the tentative title of "Coal and Costs for Synthetic Fuels" - B.M. Intermountain Field Operation Center.

Liquefaction of Coal From the Northern Great Plain States

Production of liquid fuels from coal mined in the Northern Great Plain States can establish that region as an important domestic source, supplementing the now limited crude oil in supplying fuels for the heavy energy demands by the national economy. While domestic and imported crude oil will continue as the dominant source of liquid fuels in United States for several decades, oil produced from tar sands, from oil shale, and from coal will be increasingly important in satisfying the Nation's constantly growing appetite for fuels in this most convenient liquid form. 1/ This prediction is not for the immediate future but for a later date still sufficiently advanced to permit the essential planning of the mining, reclamation of stripped areas, and plant construction.

Any one of the three sources of basic materials for synthetic oil production would have the reserves necessary to provide the needed additions to the United States oil supply for several decades. High grade oil shale deposits are mainly located in three western States. 2/ Major reserves of tar sands are located in northern Alberta, Canada, at sites still more distant from the anticipated markets. Reserve deposits of coal are widely scattered but are the most abundantly available, particularly west of the Mississippi and in the Northern Great Plain States.

1/ "Energy Research Needs - A Report to the National Science Foundation" by Resources for the Future, Inc., in cooperation with MIT Environmental Laboratory, October 1971, Chapter IV.

2/ "Oil Shale Mining, Rifle, Colorado, 1944-56." BuMines Bul. 611.

Planning for the expansion of mining and the construction of plants for conversion of coal to oil will be complicated by a number of factors. Not the least of these will be the necessity of providing large quantities of water for the processing. In addition, a massive movement of materials from the mine to the processing plant will have to be accomplished with minumum disturbance to the area. Reclamation of strip mined areas will have to be assured to a degree heretofore uncommon and requiring planning and commitments made will in advance of the actual operations.

The processes of producing oil from coal are described by "Energy Research Needs, A Report To The National Sciences Foundation", by Resources for the Future, Inc., October 1971. This description included summaries of the indicated capital expenditures and costs; however, these can now be considered only for comparative purposes. (Appendix IV-B 1 to 3)

There are many uncertainties, beginning with the costs involved in mining, transporting raw coal and other materials to the processing plant, the actual processing, the delivery of products to consumers. Capital investment costs of the large-scale mines and processing plants will be unprecedented. Lacking prior experience with such large-scale plant operations as are now contemplated by the revolutionary concept of Regional Resource Development Plants, there are no accepted guidelines for making estimates of the competitive costs and resulting price levels. For example, it may well be found that when large-scale plant operations become a reality the normally expected byproduct credits drop to zero as a result of the higher volume exceeding existing markets.

Conversion of coal to liquid fuels has been investigated extensively in the United States, but no commercial plant development has resulted. Research has concentrated on improvement of the processes which were used in Germany 30 years ago to produce aviation gasoline, in circumstances having no concern with competitive costs. 3/

The techniques used to convert coal to oil include: (1) low-temperature distillation to tar; (2) low-temperature distillation plus hydrogenation of tar; (3) Fischer-Tropsch (or gas) synthesis; and (4) hydrogenation. The last two methods have shown the greatest promise, with yields of 90 and 85 gallons per ton of coal respectively; while the first two methods give yields 30 gallons per ton of coal. 4/ However, recent results reported from the COED project, which utilizes the second technique, indicated that yields as high as 60 gallons per ton of coal can be obtained.

Annual Reports of the Office of Coal Research indicate major funding of several projects having liquefaction of coal as an objective. 5/ "Project Gasoline," conducted over a period August 1963 to August 1972, was supported to the extent of $20,377,000.

After bench scale tests, construction of a pilot plant was completed at Cresap, West Virginia, during 1967. This plant was operated until April 1970 when it was closed down for study and correction of mechanical problems

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3/ "Energy R & D and National Progress," Chapt. IV, pp. 137-143.
4/ "Energy R & D and National Progress," Chapt. VIII, p. 376.
5/ Office of Coal Research Annual Reports (Covering Cal. yrs. 1971 & 1972).

that had developed to prevent prolonged periods of plant operation. According to engineering surveys of the pilot plant, performed by several different engineering and advisory groups, it has been reported that the process used at the pilot plant was technically feasible but the mechanical reliability of the equipment used was questioned and indicated need of modifications. Recently, the Office of Coal Research has announced plans for reactivation of this facility. The Fluor Corporation has been awarded a contract to utilize the equipment and processing techniques to develop a process for the production of low sulfur fuel oil from coal, and the facility will be reactivated early in 1974.

"Project COED" (Char-Oil-Energy Development), for which $20,614,000 has been allocated by the Office of Coal Research, undertook development of coal pyrolysis in 1962 and the contract continues to February 1974. In 1970, after several years of bench-scale research, a pilot plant which can process 36 tons of coal and hydrotreat 30 barrels of coal-derived oil daily was put in operation at Princeton, New Jersey. Western coals were included in the pyrolysis processing tests, specifically a subbituminous coal mined in Sheridan County, Wyoming, and the operation was successful with an oil yield higher than with similar coals in the process development unit. 6/

6/ "Char Oil Energy Development" - R&D Report No. 73, Interim Report No. 1 by FMC Corp. to Office of Coal Research.

Summarizing results of 1972 operations of the COED pilot plant, it is reported that oil and gas yields are equal to or higher than yields from previous bench-scale work. Synthetic crude oil produced is between 1.0 and 1.5 barrels per ton of coal, depending on the type of coal used. The off-gas yield is about 9,000 SCF per ton of coal with a heating value of 650 Btu per cubic foot.

The results obtained during pilot plant operation have encouraged the Office of Coal Research to proceed under a separate contract with the design of a commercial plant and an evaluation of process economics. It is anticipated that the commercial design will be available at the end of fiscal year 1974. Results acquired to date indicate that the commercial operation of a COED plant would be economically feasible.

Research on the "Solvent Refined Coal" (SRC) process was initiated in 1962, and by 1965 had resulted in successful demonstration of the process in a 50 pounds per hour continuous flow unit. As a follow-up in 1966, an OCR contract was awarded to provide for study of the commercial feasibility of the SRC process through design, construction, and operation of a pilot plant to process 50 tons of coal per day. Design work had been completed in 1969, and after more than a year delay for funding the construction at Ft. Lewis, Washington, was started and will be completed in November 1973. Funding of the overriding contract with the Pittsburgh and Midway Coal Mining Company, to meet projected costs of construction and subsequent operation of the pilot plant now totals $28,416,437.

While awaiting completion of the SRC processing pilot plant, bench-scale development work is continued to determine the effect of operating conditions on solution of various coals ranging from lignite to high-volatile bituminous coal. This work has determined that synthesis gas is as effective as hydrogen for the solution of many coals, and the pilot plant design has already been modified to use synthesis gas as well as hydrogen for solution. A resulting reduction of processing costs is anticipated but still subject to determination by experience at the pilot plant operation.

The three research projects described above are only a partial representation of Office of Coal Research funded studies relating to conversion of coal to liquid fuels. Several projects having gasification as their major purpose will also result in findings equally applicable to liquefaction.

Technical aspects of the convertibility of coal to liquid and gaseous products have also been investigated under contracts with universities. Western coals received particular attention under a contract with the University of Utah during the period beginning August 1962 and extending to December 1969. 7/

A more recently executed contract, also with the University of Utah and jointly supported, is directed to development of production processes which will yield liquid and gaseous products from high-volatile western coals. Identified as a study of the "Intermediate Coal Hydrogenation

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7/ "Research and Development Report No. 18. Project Western Coal: Conversion of Coal into Liquids. Final Report prepared for Office of Coal Research on Contr. No. 14-01-0001-271."

Process," it will provide for a followup of prior work which has demonstrated the feasibility of hydrogenating finely ground solid coal in reactors one-eighth inch in diameter and 3 feet in length and a determination of suitable parameters for a second stage of hydrogenation. 8/

As preciously indicated, several coal liquefaction processes have been developed and are in various stages of further refinement, but as yet none have proved competitive with petroleum products from natural sources. Large scale operation would be required. These plants would have to produce approximately 100,000 barrels of liquid fuels per day and would consume 11 to 15 million tons of coal annually plus 65,000 acre-feet of water. In fact construction of such liquifaction plants is not expected in the immediate future but at a later date, perhaps 10 or more years ahead.

As an outgrowth of research and development efforts of the past decade, a new concept has evolved envisioning a multiproduct complex which is being referred to as a Regional Energy Resource Development Plant. Such a plant would be an integrated operation producing electricity, liquid and gaseous fuels, and petrochemicals. The key feature of this plant would be production of a balanced spectrum of energy products needed to meet our Nation's insatiable demands for energy. 9/

8/ Office of Coal Research Annual Report (Cl.Yr. 1972) pp. 75-76.

9/ "Combination Uses of Coal," Neal P. Cochran, Chief, Division of Utilization, Office of Coal Research. Speech presented at Fifth Intersociety Energy Conversion Engineering Conference, Las Vegas, Nevada, Sept. 20-25, 1970.

In May 1972, the Office of Coal Research announced publication of a report by Chem Systems Inc. following that company's completion of an economic evaluation and a detailed process design of a processing complex for conversion of coal to oil and gas. 10/ In summary, the processing plant designed and evaluated was called a "COG refinery," combining the Solvent Refined Coal (SRC) process with several other complementary processes concurrently under development by OCR sponsored research.

The report indicated that major products of this theoretical COG refinery would be 100,000 barrels per day of coal-derived liquid suitable for processing in a conventional fuels refinery plus 332 million SCFD of 1065 Btu/SCF pipeline gas. The liquid product, referred to in the report as light refinery liquid, would have physical qualities as follows: 650°F end point, 35°API gravity, high quality crude oil rich in aromatics and naphthenes and essentially oil sulfur content. Annual coal requirements of the complex would total 19.3 million tons or more than two and one-half times the annual production from the largest coal stripping mine presently operated in United States.

The Chem Systems Inc. evaluation estimated total investment requirements for the processing complex as shown below:

Investment	Million
Land	$ 13
Coal Mine(s)	139
COG Refinery	605
Working Capital	28
Total	$785

10/ R & D Report No. 53, Interim Report No. 4, "Development Of A Process For Producing An Ashless, Low Sulfur Fuel From Coal," Vol. I-Engineering Studies, Part 3-COG Refinery Economic Evaluation-Phase II.

In their review they stated that, based on a pipeline gas price of $.75/MM Btu and $4.50/Bbl for light refinery liquid, a discounted cash flow return on investment of 10%, after tax, could be obtained.

Utilizing Chem Systems' Chemical Refinery Linear Program, a parity evaluation of the light refinery liquid relative to Southwest Louisiana Crude was carried out. This model was used to simulate refinery operations and determine what amount a refiner could pay for the coal liquid and still obtain the same profitability as in the case of feeding the natural crude oil. This approach considered costs for the crude oil, the value of the refinery products, and the investment costs of various processing units making up the refinery; and cases were studied in which the 100,000 BPSD feed to the refinery varied between zero and 100 percent coal liquid.

The analysis indicated that, compared to $3.50 per barrel for Southwest Louisiana Crude Oil, the value of the light refinery liquid varied from $4.30 to $5.07 per barrel depending on the relative amounts of crude oil and coal liquid fed to the refinery. Using $4.50 per barrel, as was assumed in Chem Systems' estimate that a 10% cash flow return on investment could be obtained, was considered conservative.

Chem Systems Inc. concluded its summary of findings as follows:

> "The economics of the COG Refinery have been compared to the economics of several other coal gasification processes under development. These included Hygas, Bi-gas alone, Synthane, and Lurgi. Even though this is not a comprehensive evaluation, i.e., there is some difficulty in establishing a a common basis for evaluation, it shows that the COG Refinery can produce synthetic natural gas at a price significantly below the other process."

A recent report,[11] published by the Office of Coal Research, presents a detailed preliminary process design and capital investment estimate for a project to design, engineer, procure, construct and start-up a demonstration-scale plant to produce clean boiler fuels from coal. This demonstration plant will have the capacity to process 10,000 tons of coal per day and produce approximately 25,000 barrels of liquid products. The primary products consist of two grades of clean boiler fuels; secondary products are a high grade naphtha and sulfur. The liquid boiler fuels will have an energy content of approximately 145 billion B.t.u. per day which can generate 620 megawatts of electrical energy based on a 35% efficiency in the power generation stip. The largest quantity of boiler fuel will be roughly equivalent to a No. 6 fuel oil containing 0.5% sulfur and provide 65% of boiler fuel energy produced. The second boiler fuel will approximate a No. 4 fuel oil with) .2% sulfur and contain 35% of the fuel product. All energy to operate the plant will come from by-products produced from coal to the process units.

A fixed capital investment estimate was developed also for use in planning future budgets. A capital cost of $270 million was determined for the facility. Included in this estimate are the necessary ancillary facilities required to efficiently operate a grass-roots complex.

In addition to the fixed capital investment for the physical facilities, it is estimated that an additional investment of $40 million would be required to carry the project through the startup period. The estimated total capital expenditure, excluding interest during construction, therefore, is approximately $310 million through start-up.

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[11] "Demonstration Plant - Clean Boiler Fuels from Coal, Preliminary Design/Capital Cost Estimate," R&D Report No. 82, Interim Report No. 1, prepared for the Office of Coal Research by The Ralph M. Parsons Co., OCR Contract No. 14-32-0001-1234.

Although the above described reports represent the most recent evaluation of OCR sponsored research on liquifaction, some previous estimates were described in other reports to the Office of Coal Research. For example, in 1969 Ralph M. Parsons Co. evaluated the Consol synthetic crude process, assuming that a plant to produce 250,000 barrels per day from Western coal would cost $633 million and be capable of producing synthetic crude at a cost of $3.25 per barrel from coal at $1.25 per ton.[12/] For comparison, the 1969 crude prices in Wyoming were $2.85 to $3.25 per barrel. Currently, at the close of 1973, crude prices in Wyoming have increased to an estimated $3.34 per barrel, while coal prices have increased very substantially due to the heavy demands for low sulfur coal and to escalation of wage and supply costs. Thus, conditions have changed since the evaluation made in 1969.

Several companies have already made public their interest in constructing gasification units of 250 million cubic feet per day capacity, and the plans of one company have already advanced to the point of applying for water allocations from the Missouri River. Assurance of water availability ranks high on the list of problems to be solved before coal gasification or liquefaction processing can be justified as commercially feasible in the Northern Great Plain States. Problems of financing the new mines and gasification and liquefaction plants are also ranked as major problems for solution.

[12/] R & D Report No. 45, Interim Report No. 2, "Feasibility Report on Consol Synthetic Fuel Process Synthetic Crude Production" - prepared for Office of Coal Research, July 1969.

Preliminary estimates indicate that Lurgi gas plants could be put in operation in the Fort Union area of the Dakotas, Montana, and Wyoming within a decade. 13/ Gasification instead of liquefaction appears to have priority as the type of conversion process which will first be applied to subbituminous coal and lignite mined in the Great Northern Plain States.

13/ "Coal Development in Eastern Montana - A situation report of the Montana Coal Task Force."

APPENDIX IV-B.

LIQUEFACTION ECONOMICS

APPENDIX IV- B1

ECONOMICS OF MAKING SOLVENT REFINED COAL a/

	Without coking	With 10 percent coking	With 25 percent coking
Investment costs:			
Mine	$ 23,555,000	$ 23,555,000	$ 23,555,000
Plant	71,381,000	79,632,000	86,648,000
Total	$ 94,936,000	$103,187,000	$110,203,000
Operating costs:			
Mine	$ 10,060,000	$ 10,060,000	$ 10,060,000
Plant	10,757,600	11,393,800	11,702,900
Total	$ 20,817,600	$ 21,453,800	$ 21,762,900
Cash earnings required for 10 percent DCF return b/	+14,400,000	+16,100,000	+17,500,000
Total	$ 35,217,600	$ 37,553,800	$ 39,262,900
By-product credits	-16,930,000	-22,488,000	-30,861,000
Required return from de-ashed coal product	$ 18,287,600	$ 15,065,800	$ 8,401,900
Total de-ashed coal product available:			
Tons/year	1,950,000	1,709,300	1,350,800
10^6 Btu/year	62,000,000	54,400,000	43,000,000
Required selling price of de-ashed coal product:			
Cents/10^6 Btu	29.5	27.7	19.5
Cents/10^6 Btu if by-product credit in error 20 percent	35.0	36.0	33.8

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a/ Coal consumption = 833,333 pounds/hour; de-ashed product in liquid state.

b/ Includes depreciation

Source: R & D Report No. 53, Interim Report No. 1, prepared for Office of Coal Research, June 1970.

ECONOMIC SUMMARY FOR H-COAL (100,000 barrels/stream-day refinery)

Principal products (10^3 barrels/stream day)				Type of hydrogen reformer a/	Percent return on investment	
Gasoline	Furnace oil	LPG	Benzene		As book profit b/	As total cash flow c/
Illinois No. 6 Bituminous coal						
67	33	-	-	Natural gas	8.31%	16.11%
100	-	-	-	Natural gas	9.27	17.14
100	-	12	3	Natural gas	10.10	18.03
67	33	-	-	Coal and char	7.49	15.23
100	-	-	-	Coal and char	8.38	16.17
100	-	7.4	3	Coal and char	9.06	16.91
Wyoming subbituminous coal						
67	33	-	-	Natural gas	6.88	14.57
100	-	-	-	Natural gas	7.87	15.63
100	-	12	3	Natural gas	8.55	16.36
67	33	-	-	Coal and char	6.64	14.31
100	-	-	-	Coal and char	7.53	15.27
100	-	12	3	Coal and char	8.32	16.12

a/ Process makes enough gas for hydrogen manufacture except in third case from top. Reformer is fired with natural gas or coal and char.

b/ Book profit = profit - taxes at 48 percent of profit, where profit is revenue - expenses (excluding taxe

c/ Total cash flow = book profit + depreciation (15-year straight line) + tax credit (7 percent of plant investment spread over payout period for plant). (Figures are totals.)

Note: For comparison purposes, these figures as well as those of other processes would require cost updating and normalization.

Source: R & D Report No. 45 prepared for Office of Coal Research, November 1968.

ECONOMICS OF COED PROCESS

Case	I	II	III
Product gas	hydrogen	fuel gas	hydrogen
Process fuel	gas	gas	char
Fixed capital ($ million	$36.17	$32.70	$44.65
Working capital ($ million at 7 percent of fixed capital)	2.53	2.29	3.13
Total investment	$38.70	$34.99	$47.78
Manufacturing costs ($ million/year):			
Coal at $3/ton(11.8 cents/million Btu)	$10.50	$10.50	$10.50
Oxygen at $6/ton	1.73	1.73	1.73
Utilities	1.70	1.39	2.36
Taxes, insurance, maintenance and depreciation	4.34	3.93	5.36
Labor, supplies, PAC, and overhead	1.20	1.20	1.44
Total manufacturing costs	$19.47	$18.75	$21.39
Product value ($ million/year):			
Char at $2.75/ton	$ 4.78	$ 4.78	$ 3.33
Oil at $4/barrel	18.80	18.80	18.80
Hydrogen at 25 cents/thousand standard cubic feet	3.90	-	-
Fuel gas at 11.8 cents/million Btu	-	0.87	-
Total	$27.48	$24.45	$33.83
ASR -- 5 percent sales	$ 1.38	$ 1.22	$ 1.69
Net sales value	$26.10	$23.23	$32.14
Gross profit	6.63	4.48	10.75
Net profit (after 50 percent tax)	3.31	2.24	5.38
Percent return (before taxes)	17.3%	12.8%	22.5%
Discounted cash flow rate of return percent	13.0	10.0	16.0

Note: For comparison purposes, these costs as well as those of other processes would require updating and normalization.

Source: R & D Report No. 56. Interim Report No. 1, prepared for Office of Coal Research, May 1970.

PART V.

TRANSPORTATION OF ENERGY FROM THE NORTHERN GREAT PLAINS REGION

Unit Train Transportation of Coal from Northern Great Plains States

Unit train haulage of bituminous coal costs less than 1 cent per ton-mile. For haulage distances of 450 miles, this highly coordinated and efficient system of coal transportation by railroads has held the haulage costs down to 13.1 cents per million Btu when cars were furnished by the railroad and to 6.6 cents when cars were leased by the producer - not furnished by the railroad. These were the indications of case studies of nine representative unit train operations reported in Bureau of Mines Information Circular 8444, published in 1970.

Quoted from the introduction to IC 8444, a well-phrased explanation makes clear the basis for success of unit trains in holding down transportation costs:

> "The unit train is a management technique that permits efficient planning through long-range contractual commitment of producer and consumer and dedication of equipment. Specifically, a unit train consists of a dedicated set of haulage equipment loaded at one origin, unloaded at one destination each trip, and moving in both directions on a predetermined schedule.
>
> The unit train combines three principal factors: design efficiency, equipment balance, and intensive use. To achieve the lowest possible transportation cost, all elements of the operation must be in balance; the loading, haulage, and unloading facilities must be designed and scheduled for intensive use but not to a degree that would bring intolerable maintenance costs; and the haulage capacity must be in balance with supply, with the consumer's needs, and with amortization requirements."

Although not brought into use until 1959, unit train transportation of coal--after a slow start--grew rapidly in the middle and late 1960's as a result of technological advances, better planning by management, and improved overall efficiencies. In 1972 the movement of bituminous coal by unit trains totaled 136.5 million tons or 34.7 percent of total United States coal shipments by railroads.[1]

In terms of freight rates in effect, the unit train is not a unit train until so designated by the carrier and negotiations for the rate completed. Cooperation between the shipper, the carrier, and the consumer is essential to planning for successful operation which will justify the lower rates.

Lowest costs can be realized when a unit train movement is limited to a single line haul. When more than one carrier is involved, the additional capital cost for motive power and additional operating costs will be accompanied by higher tariff rates.

In the four Northern Great Plains States, the following railroads operate in or adjacent to the region under which the Ft. Union subbituminous coal formation is found:

Burlington Northern, Inc. (moves 60 percent by unit trains)
Chicago, Milwaukee, St. Paul, and Pacific
Soo Line Railroad
Union Pacific Railroad

As a practical matter, one or more of the above railroad companies will probably become involved in any future expansion of unit train coal movements from or within the Northern Great Plains area. However, it is possible that such movements can be by private railroad as illustrated by shipments of coal from a mine in Converse County, Wyoming, to the Pacific Power and Light Company's Dave Johnson generating plant.

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[1] Coal--Bituminous and Lignite In 1972.

Potential rate reductions by adoption of unit trains vary for each specific movement. One highly significant factor affecting such savings is the ownership of cars in which shipments are made. If owned by the shipper or the consignee, it is possible for the railroad to make lower rates as it reduces their own capital requirements. However, since taking cars out of the unit train for repairs is extremely disruptive, some railroads prefer use of their own cars in order to be assured of the more dependable service from premium cars built to their own specifications. 2/

The amount of capital requirements for unit trains varies generally with the number and type of cars. Bottom dumping cars cost more than rotary dumping cars, but use of the latter requires more expensive unloading facilities. The current price of an open top hopper car, built to minimum standards, is approximately $17,000, whereas a premium open top hopper car will sell for about $19,000. Over an expected 40-year life, the additional $2,000 paid for premium cars will be more than offset by savings of $4,000 to $11,000 resulting from less frequent rebuilding. In addition, the greater reliability of the premium cars will contribute to improved equipment utilization and successful unit train operation. Not infrequently, annual car mileages for unit trains range from 100,000 to 250,000 miles, which represents a utilization which is at least ten times that of cars assigned to conventional train service. 3/

2/ Morris, Robert N., "Unit Train Ownership and Economics In The Expansion of Coal Markets", The Railway Management Review, Vol. 73 No. 3, 1973.

3/ Sward, John D., "The Total System and The Role Of The Unit Train", The Railway Management Review, Vol. 73 No. 3, 1973.

Expansion of railroad facilities to transport increased tonnages of coal from the Northern Great Plains to coal-fired electric generating plants and to the projected regional coal conversion plants outside the region will require substantial capital expenditures, but within the scope of this report, only a general indication of the magnitude of the capital required can be furnished. To a certain extent this requirement depends on how much equipment has already been acquired in anticipation of the expansion and how may be transferred from other regions or made available by improved utilization of existing hopper cars and locomotives.

As estimated from an assumed 100-car unit train operation, making 50 round trips per year and delivering an aggregate of 500,000 tons annually, it will be necessary to acquire and assign to unit train use 105 hopper cars. Of this number, one-hundred will be for the regular unit train use; five will be spares. The 105 will cost not less than $2,100,000 in 1973 dollars. In addition, it is assumed that 5 locomotives will be needed to provide the necessary motive power, and a caboose will be required for the train. Five locomotives cost approximately $1,500,000. Loading and unloading facilities to permit the essential rapid handling will involve expenditures of about $500,000, according to current trade reports. Thus, exclusive of any new rail mileage laid down to connect the mine site and existing main rail lines, capital expenditures required to provide for unit train movement of 500,000 tons annually will total about $4,000,000. To move 5 million tons annually will require ten unit trains and estimated capital expenditures totaling $40,000,000.

Technology for unit train transportation of coal, as of 1970, was described for nine representative examples of operations in Bureau of Mines Information Circular 8444, from which the attached summary of the case studies has been furnished. (Appendix V-1A) Haulage distances varied but the comparison of costs per ton-mile indicated lower haulage costs when cars were supplied by the producer or the consumer, not the railroad. Although no mines in the Western States were included in the cases studied, experience of both underground and strip mine using unit trains was reported, based on information from coal operators, railroads, and equipment manufacturers.

In 1972, 47.2 percent of total Northern Great Plains coal production was moved by unit trains. Originating at Colstrip, in Montana, a 10,000 ton capacity unit train to Hammond, Indiana, takes seven days and carries a rate of $8.60 per ton. From the same point of origin to St. Paul, Minnesota, unit train movements takes five days and carries a rate of $5.00 per ton. The average freight cost per ton mile was only 6.8 mills for the 1,273 mile trip to Hammond; and 6.2 mills per ton mile to St. Paul, a distance of 804 miles. The above rates and cost per ton-mile averages illustrate the application of low rates on coal movement by unit trains from the Northern Great Plains. One further example, based on a recently quoted rate for movement from a Belle Ayre, Wyoming mine to East St. Louis, Illinois indicates that a 1,089 mile movement can be made at a cost of 6.4 mills per ton mile. (Appendix V-1B and V-1C).

APPENDIX V-A.

UNIT TRAIN DATA

V-5a

APPENDIX V-1A

TABLE 1. - Summary of case studies

General information	Inland Steel mine	Valley Camp No. 3 mine	Captain mine	Lancashire No. 20 mine	Orient No. 5 mine	Bellcoal Inc.	Matthews mine	Bell & Zoller No. 9 mine	Trenton Channel facilities
Location	Illinois	West Virginia	Illinois	Pennsylvania	Illinois	Kentucky	Tennessee	Kentucky	Ohio
Source of production	Underground	Underground	Strip	Underground	Underground	Strip	Underground	Underground	Strip
Reserves............years.	40	50	30	25	20	35	20	27	40
Quality of coal	Metallurgical and steam	Steam	Steam	Steam	Steam	Steam	Steam	Steam	Steam
Calorific value....Btu/lb.	12,584, 11,000	13,500	10,780, 11,200	13,013	11,000	12,720	13,200	11,520	12,200
Date of first unit train	July 1968	Jan. 1965	Oct. 1964, Jan. 1966	Aug. 1967	July 1968	Mar. 1966	Jan. 1968	Sept. 1967	Sept. 1967
Type of storage	3 silos	1 silo	Ground	Ground	Ground	Ground	Ground	Ground	Ground
Capacity of storage..tons.	42,000	11,000	94,000	36,000	30,000	14,400	40,000	60,000	55,000
Shape of storage	Silo	Silo	Windrow	Conical	Conical	Conical	Conical	Kidney	Conical
Ventilation of storage	Fan	Fan	Fan	Fan	Fan	Natural	Natural	Fan	Natural
Coal preparation	Clean	Clean	Blended, clean	Clean	Raw	Raw	Clean	Raw	Raw
Size of coal	1.5 in. by 0, 0.75 in. by 28 mesh	2 in. by 0	3 in. by 0, blended; 2 in. by 0, clean	1 in. by 0	1.5 in. by 0	3 in. by 0	5 in. by 0	2 in. by 0	4 in. by 0
Number of unit trains	1	1	2	1	1	1	1	1	1
Haulage distance miles. 1 way.	279	450	306,354	180	130	333	457	129 rail, 275 barge	317
Cars per train	125	105	126, 102	105	70	84	96	72	82
Type of cars	Hopper	Hopper	Gondola	Hopper	Hopper	Hopper	Gondola	Hopper	Gondola
Capacity of car.... .tons.	100	50-84	100	100	100	80	110	100	100
Ownership of cars	Consumer	Railroad	Consumer	Consumer	Railroad	Railroad	Leased by producer	Leased by railroad	Leased by producer
Minimum tons per shipment.	12,500	7,000	12,600, 10,200	10,500	7,000	7,000	10,000	7,500	8,200
Minimum tons per year	1,500,000	-	3,300,000, 1,400,000	1,800,000	1,000,000	1,400,000	1,500,000	1,750,000	1,800,000
Loading track layout	Rail loop	2 single tracks	4 parallel tracks	Single track	Single track	Single track	Rail loop	Rail loop	Single track
Means of moving cars while loading.	Locomotives	Locomotives	3 car hauls	Locomotives	Locomotives	Locomotives	Locomotives	Locomotives	Locomotives
Rate of car movement..fpm.	22	25	20	21	30	24	30	30	28
Loading rate..........tph.	4,000	2,500	2,700	3,200	2,400	2,600	3,000	3,300	3,000
Cost per ton (haulage tariff rate).	$1.50	$3.53	$1.35, $1.83	$1.50	$1.00	$1.79	$1.75	$1.01 rail, $1.30 barge	$1.66
Cost per ton mile (haulage).	$0.0054	$0.0078	$0.0044, $0.0052	$0.0083	$0.0077	$0.0054	$0.0038	$0.0078, $0.0047	$0.0052
Percent of production shipped by unit train.	100	65	100	100	57	100	100	100	55
Shipping cost per million Btu.	$0.060, $0.068	$0.131	$0.063, $0.082	$0.058	$0.045	$0.070	$0.066	$0.044, $0.056	$0.068

Source: Bureau of Mines IC 8444

Unit Train and Volume All-Rail Tariffs On Coal Shipments From Montana and Wyoming Mines

Origin & Destination	Tariff Reference	Effective Date	Minimum Train Load Tonnage	Annual Minimum Tonnage	Rate[1] Per Ton	Distance In Miles	Average Transportation Cost	
							Per Ton/Mile (Mills)	Per Million Btu (Cents)
Colstrip, Montana to Cohasset, Minnesota	ICC37;BN38	8/13/73	10,200	1,000,000	$ 3.69	773	4.8	21.2
			10,200	1,500,000	3.45	773	4.5	19.8
			10,200	1,750,000	3.23	773	4.2	18.6
Colstrip, Montana to Northtown, Minnesota	ICC40;BN5-A	7/ 1/73	6,600	700,000	4.73	793	6.0	27.2
Colstrip, Montana to St. Paul, Minnesota	ICC64;BN57	7/ 1/73	6,600	400,000	5.00	804	6.2	28.7
Decker, Montana to Minneapolis, Minnesota	ICC162;BN152-A	8/13/73	5,300	200,000	6.00 [2]	968	6.2	31.6
Kleenburn, Wyoming to Northtown, Minnesota	" "	8/13/73	5,300	200,000	5.80	1,094	5.3	30.5
Kleenburn, Wyoming to St. Paul, Minnesota	" "	8/13/73	5,300	200,000	6.09	1,105	5.5	32.1
Colstrip, Montana to Waukegan, Illinois	ICC19;BN19	1/22/73	10,000	450,000 (One destin.)	8.38	1,250	6.7	48.2
Colstrip, Montana to Hammond, Indiana	" "	1/22/73	10,000	900,000 (Two destin.)	8.60	1,273	6.8	49.4
Colstrip, Montana to Havana, Illinois	ICC5;BN7	7/ 1/73	10,000	900,000	8.91	1,279	7.0	51.2
Kleenburn, Wyoming to Powerton, Illinois	" "	7/ 1/73	10,000	900,000	8.54	1,129	7.6	45.0
Decker, Montana to Havana, Illinois	ICC121;BN119	7/ 1/73	9,700	3,300,000[3]	8.62	1,168	7.4	45.4
Decker, Montana to Powerton, Illinois	" "	7/ 1/73	9.700	3,300,000[3]	8.62	1,129	7.6	45.4
Colstrip, Montana to Plaines, Illinois	ICC30;BN33	1/23/73	9,500	900,000	8.99	1,275	7.1	51.7
Belle Ayr, Wyoming to E. St. Louis, Illinois	ICC176;BN164	7/ 8/73	9,700	1,500,000 (18 Mo.)	6.97	1,089	6.4	42.5
Belle Ayr, Wyoming to Pueblo, Colorado	ICC178;BN165	6/18/73	10,500	1,670,000	3.10	600	5.2	18.9

1/ Rates subject to conditions in tariffs and specified penalties for delays of loading or unloading.
2/ Applicable only for reshipment beyond Minneapolis via barge.
3/ Volume requirement during first 24 months; in each succeeding 12 months requirement is 2,200,000 tons.
Source: Compiled by Branch of Interfuels and Special Studies, Fossil Fuels Division, U.S. Bureau of Mines,, from tariffs furnished by Burlington Northern, Inc. September 25, 1973.

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UNIT TRAIN AND VOLUME ALL-RAIL TARIFFS ON SELECTED WESTERN COAL SHIPMENTS*

Origin & Destination	Tariff Ref.	Effect. Date	Minimum Train Load Tonnage	Annual Minimum Tonnage	Rate Per Ton	Distance in miles 1/	Average Trans.Cost (Mills/ton/mi)
Carbondale,Colo. & Sunnyside, U. to Kaiser, Cal.	ICC 1162;RG 7509	1/173	Sunnyside 8,400	750,000	$5.46	811	6.73
			Sunnyside & Carbondale 6,400 Alternate shpmt. allowed, with at least 250,000 tons from Carbondale	550,000 2/	$6.80	1,047	6.49
Somerset, Co. & Columbia & Sunnyside U. to Geneva, Utah	ICC 1198;RG 7510	1/173	Columbia or Sunnyside 2,600 min.	1,300,000 total vol.	$1.945 3/ Col. or Sun.	128	15.20
			3,700 max. Somerset	clean coal	$3.04 Somerset	351	8.56
Carbondale, Co. to Geneva, Utah	ICC 1198;RG 7511	1/1/73	3,200 min. 6,000 max.	over 350,000	$2.75	362	7.60
Allen to Minnequa, Co.	C & Wyo. Ry. #2	5/20/73	4,000	1,300,000	$1.60	124	12.90
Price, U. to Gadsby,U.	ICC 1066;RG 6058	9/11/72	2,400	360,000	$2.43	130	18.69
Routt Cty. to Den. Colo.	RG 7493	10/1/73	3,000	1,750,000	$2.16	200	10.80

*Except for the last two listings, tariffs on this summary tabulation apply to metalurgical coal.

1/ Distances shown are one-way. Unit trains from Sunnyside to Kaiser cycle in four days; load in 1 hour.

2/ Alternate trips from Sunnyside & Carbondale count toward 550,000 annual minimum; at least 250,000 tons is the required annual shipment from Carbondale.

3/ Mines at Somerset and Columbia ship raw coal to a cleaning plant at Wash, then to Geneva. At Sunnyside the coal is prepared at the mine and shipped to Geneva.

Source: Compiled by Branch of Interfuels and Special Studies, Fossil Fuels Division, U.S. Bureau of Mines from information furnished by Denver & Rio Grande Western RR. October 18, 1973.

PIPELINE TRANSPORTATION OF COAL FROM N.G.P. MINES

Transportation of coal by pipeline, potentially, may be accomplished at lower cost than by unit trains. High volume, long distance movement, and continuity over an extended period of years are necessary conditions to attainment of such low costs of transporting coal through a pipeline. However, the technology of pipeline transportation of coal has been developed well beyond the experimental stage and is available for practical application in movement of coal produced in the Northern Great Plains States.

Transportation of coal through a pipeline is a relatively simple technique by which fine-size particles of coal are mixed with water and the resultant liquid is pumped through pipes, stored, and handled in the same manner as fuel oil. The mixture contains coal particles ranging in sizes from a maximum of 1/8 inch down to sizes finer than granulated sugar, and is most commonly referred to as coal slurry. This coal slurry can be stored tanks providing some agitation is continued to keep the coal in suspension.

The cost of transportation of coal slurry by pipeline is a function of the annual tonnage transported, the distance, the physical characteristics of the coal, the conditions of the terrain, and the annual capital charges of the pipeline.[1/] Most significant of these several factors are the annual tonnage and distance.

An industry official having intimate knowledge of coal slurry pipeline operation has stated that in general, assuming movement of 5 millions tons per year or more, there is a good chance that a slurry pipeline can be competitive if the competing freight rate is higher than one-half cent per ton per mile.[2/] This same official pointed out that the energy shortage, to a great extent, is a transportation shortage -- with existing sources of energy found to be increasingly further from the markets to be served. For that reason, coal slurry pipelines are one of the methods to be given serious consideration when making the decision on transportation of energy available from the reserves in the North Great Plains. Furthermore, in a situation that requires long-term contracts -- running 20 to 35 years -- costs of pipeline transportation will escalate less than costs of railroad movement or costs of any other means of transportation. For pipelines, an estimated 70% of costs are capital related fixed charges which can remain practically unchanged after installation settles the total to be amortized. Power costs, also relatively stable, make up 15% of the total; and only 15% remains for other charges and labor costs which may be expected to escalate at regular periods of negotiated wage rate increases.[1/]

From time to time, there has been consideration of transporting coal in a slurry of liquids that have been made from coal, thus gaining the advantage of having no transportation cost of the water component which normally makes up 40 to 50 percent of the coal slurry by weight. By employing this technique, something near double the Btu content can be handled in the pipe with no additional pumping costs or capital investment. One further advantage, of considerable magnitude, is that use of coal-derived oil or liquid would sharply reduce or eliminate use of water as the transport medium. For application in the Northern Great Plains where water is available only at a premium, this advantage would be magnified.

In the United States, the first cross-country pipeline transporting coal was built in 1957 and put into service beginning 1958. This pipe was 10 inches in diameter and 108 miles long, running from a mine near Cadiz, Ohio to the Eastlake plant of the Cleveland Electric Illuminating Plant in the outskirts of Cleveland. After several years of successful operation, the pipeline was taken out of service in 1963 when it had forced drastic reductions of rail freight rates and made rail haulage more economical.

The Cadiz-Cleveland pipeline was built to carry 1,250,000 tons per year, but it exceeded that capacity in actual performance by transporting 1,384,000 tons in 1959; 1,316,000 tons in 1960; and 1,440,000 tons in 1961. Consolidation Coal Company built, operated, and maintained the slurry preparation plant and pipeline. The de-watering and drying facilities were the responsibility of the Cleveland Electric Illuminating Company. Total cost of the 108 - mile pipeline was more than $13,000,000, including $2,500,000 for the de-watering and drying plant.[3]

According to a statement by the fuel purchasing agent for CEI, in November 1961, the capital investment was amortized on a $1,250,000 basis, making possible the low $1.95 per ton cost of moving the coal through the pipeline.[3] By comparison, the rail rate at that time, late in 1961, was $2.49 per ton after having been reduced $1.05 per ton since operation of the pipeline began in 1958. Subsequent rail rate reductions applying to much larger tonnages, and made possible through adoption of the unit train concept of coal movement, resulted in "moth-balling" of the Cadiz-Cleveland pipeline.

After beginning the pipeline operation with a 50-50 mix of pulverized coal, it was shortly found that a 60 coal - 40 water reduced cost and made easier de-watering at the generating plant. This change in the slurry mix, bringing the water content closer to a 70-30 consist usable for direct combustion at the generating plant was described as a break-through of major importance.[4]

Steel for the Cadiz-Cleveland pipeline was high carbon. After welding, the pipe was wrapped and laid underground below the frost line. The pipe was cathode protected, and the water used in the slurry was treated by addition of a chromate to reduce erosion.

Pumps used in the system were motor-driven plunger type pumps similar to those used on oil pipelines and were capable of applying necessary high pressures, assumed to be in the order of 1,000 to 1,600 pounds per square inch. Electric power used for pumping was a significant item of the operating expense.

Estimates indicate that a 14 inch pipe would have had a capacity of 4 million tons annually; a 16 inch pipe would have transported approximately 6 million tons; and a 20 inch pipe would have had a capacity of 8 to 10 million tons per year.

The economics of moving coal by pipeline are similar to those of pipeline transportation of oil and gas. After the pipeline system is installed, the cost of moving coal slurry through it is largely the prorated fixed costs of the installation. Pipeline designers who planned and built the Cadiz-Cleveland line claimed that larger lines could be built, utilizing the experience and advanced technology gained, to transport coal at as low as 3 mills per ton mile.[5]

The second cross-country coal slurry pipeline was built in 1970 to transport coal from the Black Mesa mines, near Kayenta, Arizona, to the Mohave power plant in Nevada over a distance of 273 miles. The power plant supplied is a 1,500 megawatt installation requiring approximately 5 million tons of coal annually.

The Black Mesa pipeline has now been in operation nearly two years, with apparent success. It has been reported that some problems have been experienced in plugging of the line when the slurry does not contain a sufficiently high percentage of fines. Furthermore, it has also been a serious problem and has been accentuated by higher percentages of fines. In this experience, the slurry which transports most readily through the pipeline without plugging has caused loss of efficiency at the point of consumption due to added difficulty of reducing the water content. Hopefully, changes of operating procedures or improved equipment will soon solve these problems.

The Black Mesa pipeline is an 18 inch pipe laid 3 feet or more underground over a rugged terrain. There are five pumps, with four pumping stations operated to keep the slurry moving at the critical rate of 4 to 7 feet per second -- approximately 3.75 miles per hour as an average. The maximum grade on the line is said to be 18 degrees, and whenever possible it is held to less than 16 degrees. At the starting point, near the mine on Black Mesa, the elevation is 6,600 feet. The line runs down to 4,200 feet, then goes up to 6,500 feet, and finally drops down to 500 feet at the terminal near the Mohave generating plant. The line crosses under beds of the Colorado river and other smaller streams. The pipeline was designed to handle 660 tons per hour running 8,400 hours per year; and it takes 43,000 tons to fill the pipe.[6]

The slurry transported is 50-50 coal and water, by weight. For each year's operation at capacity the line requires 3,200 acre feet of water, and over the 35 year life of the operation it is estimated that annual water requirements will average 2,400 acre feet. To supply this quantity, Peabody Coal Company drilled five mines to depths of 3,535 to 3,737 feet and two miles apart, sealing the well shafts with concrete down to the 2,000 foot level so as to avoid taking water from any of the top water-bearing sandstones that have been depended on by the Navajos and Hopis living in the vicinity of the head of the Black Mesa pipeline.

Under leasing agreements, extending for a ten-year period, the coal company pays $6.67 for each acre foot of water pumped for use in the pipeline. The company is required to provide the Indians with water in quantity and quality equal to that formerly available to them or obtain water for the slurry operations from another source if the Secretary of Interior finds, at any time, that the local supply is endangered.[7] When the mining operations are completed, the five deep wells will be turned over to the tribes. Meanwhile, a monitoring system is being set up by the U.S. Geological Survey, at the request of the Bureau of Indian Affairs, to make certain that the company complies with the Indian leases.

On the basis of extensive hydrologic surveys, conducted for Peabody Coal Company by independent specialists, the planning for the wells was followed by drilling of the deep wells and use of the water in the coal slurry. It is estimated that there are 10 million acre feet of water in the Navajo-Kayenta-Windgate sandstone formations from which the wells draw-water. Water required for slurry operations of the pipeline, over a 35-year period, would be only 1% of the estimated water in storage in those formations. Net withdrawal would be even less if nature recharges the sandstone.

The Black Mesa coal slurry pipeline transports the equivalent of 160 rail cars of coal daily, with a minimum environmental disturbance. In fact, water consumption and water disposal are the principle environmental impacts. The former has been illustrated above. Although the pipeline does require about 3,000 acre feet of water annually, that quantity is only 15% of the annual water requirement of the 1,500 megawatt electric generating plant to which the coal is transported.

Water disposal at the terminal of the pipeline involves separation, by centrifuge and other means, and possible use of the resultant water on the cooling tower of the generating plant. Finally, evaporation or treatment for discharge into rivers or lakes is required, and planning for this is essential.

Disposal of slurry removed from plugged or broken pipelines is another potential environmental problem, but it is one which should arise less frequently as the determination of proper slurry mix is derived from experience. Essentially, this problem is not much different from the problem of clean-up after a railroad car derailment, but it probably will occur in a more remote area from which recovery of the coal residue will be difficult.

Reliability of the coal slurry pipeline is very important to the electric generating plant which depends on it. The record of the Cadiz-Cleveland plant was good in this respect and supported a claim to an "availability factor" of 98 percent. There should be no interruptions due to weather, unless indirectly due to the power lines being down in a storm with the result that pumping stations lose their power and have no alternative. In addition, pipeline operations should be relatively free from labor disputes.

Relatively few workers are required to maintain a pipeline after it has been installed. On the Black Mesa pipeline, all of the stations are remotely controlled over a private microwave system, and the System Operator is able to supervise the entire line operation, including the rate control of the conveyor belt coming from the Peabody Coal storage facility to the Black Mesa preparation plant.[2/] It is reported that only 33 work on maintenance of the pipeline, running some 273 miles. This confirms the fact that pipelines have small operating expenses, confined to the pumping expense and employment of a small number required to maintain the line.

With reference to employment at the strip mines supplying a coal slurry pipeline, only 150 employees are required to produce the 5 million tons moved by pipeline to the Mohave electric plant. The Peabody Coal Company has estimated that expansion of the mine to provide for the three 770 - megawatt electric generators at Page, Arizona will increase the mine's work force to 375, with an estimated 80 percent to be Indians.

The above prediction anticipates an average strip mine production of 35,000 tons per man per year, and this average can be adopted as a practical guide-line to estimating the employment additions which would be brought about by expansion of strip mining in the thick seams of the Northern Plain States presently under review. The range of county averages varies quite widely, but during 1971 production per man per year at strip mines in Rosebud County, Montana exceeded 49,000 tons. In Converse County, Wyoming the average was slightly over 36,000 tons per man per year.8/

Installation of a coal slurry pipeline requires right-of-way, but after the pipe has been put down there is little permanent land area required. The land disturbed by excavation for the pipeline can be revegetated, although some time is necessary to accomplish this in dry areas. Pipelines do not interfere with free movement of vehicles, people, or animals. With the pipe laid below frost-line, operations can be continued throughout the year without any of the difficulties experienced in winter rail shipments.

In construction of the Cadiz-Cleveland pipeline, it was possible to put the line into operation without using eminent domain; rights-of-way were obtained by negotiation. In exchange for permission to cross the right-of-ways of the three principal rail carriers, the railroad companys were given an option to purchase up to 45 percent of the line -- although this option was never exercised.9/

In early 1962, when a coal slurry pipelines for movement of West Virginia and Pennsylvania coal to electric generating plants and other fuel consuming customers in Maryland and New Jersey were being proposed, national legislation granting the right of eminent domain to such pipelines was sought. To accomplish this end, S.3044 -- a bill to amend the Interstate Commerce Act to grant to any carrier of coal by pipeline the right of eminent domain -- was introduced in the U.S. Senate and became the subject of extensive hearings.10/

One of the most publicized of the potential pipelines was one extending from Pennsylvania and West Virginia bituminous coal mines to the east coast, consisting of a network of collecting and main lines totaling more than 400 miles length. The system was to serve a group of coal producers supplying a number of fuel consumers. At that time, May 1962, the total capital expenditure requirement of this system with a 6 to 8 million ton annual capacity was estimated at $80 to $100 million.

Testimony given at the hearings on S. 3044 indicated that the underlying purpose of the bill was to lower the transportation cost of coal, especially that produced in depressed coal mining areas, and to make coal more competitive with other fuels used in generation of electricity. In this connection, a question was asked as to whether the Committee should consider granting of power to regulatory agencies to approve experimental and incentive rates by railroads and other coal carriers in addition to the consideration being given to power of eminent domain for coal slurry pipelines.

Senate bill S.3044 was supported by leading commercial coal producing companies individually and through the National Coal Association representing about two-thirds of the total commercial bituminous coal production. The

United Mine Workers supported the proposed bill as legislation which was expected to aid in expansion, or retention, of bituminous coal markets and employment. However, the West Virginia Independent Coal Operators Association, representing several small coal producers and small coal land owners, opposed enactment of the bill.

The most vigorous opposition came from railroads. On April 1, 1962, just prior to the start of the Coal Slurry Pipeline hearings, the Pennsylvania Railroad announced that it had negotiated with the Pennsylvania Power and Light Company drastically lower rates for transport of coal in special trains which would operate as units carrying 6,000 tons of coal on fast scheduled runs between Indiana County mines and the generating plant in eastern Pennsylvania. This new "integral train" concept was publicized as the answer to coal slurry pipelines. It was described in the following words from the president of the Pennsylvania Railroad:

> "Newly designed facilites at the mine and at the power plant will speed up loading and unloading time and provide for storage in volume. The trains will be loaded at the mine in 3 hours."
> "...this 'flexible fuel line on rails' moving coal in large volume on fast schedules and at low cost, should beat coal pipelines in every factor of service and economics and sound the death knell to the grandiose plans being made in some quarters to take almost half the railroads' coal business away from them."

The Transport Workers Union of America, AFL-CIO, vigorously opposed S.3044 and were joined in this opposition by the Railway Labor Executives Association composed of the chief executives of 24 national or international labor organizations representing substantially all employees in the railroad industry. In their view, pipelines introduced to transport coal slurry were a threat to railroad employment which was already depressed; therefore, they felt justified in taking the strongest stand against any federal legislation which would grant eminent domain to coal slurry pipelines.

Witnesses from major coal carrying railroads made it clear that they felt it improper to have the federal government grant eminent domain to a coal slurry pipeline, which by its very nature was essentially a private commercial operation which was not designed to provide transportation services for all shippers and consumers of coal, large and small alike. In effect, they said that there was no overriding reason why coal pipelines, like the railroads, should not look to the legislatures of the various States for authority to condemn property. The legislature of each individual State was considered the proper forum to determine the extent to which coal pipelines might be in public interest and providing public services justifying the grant of eminent domain.

No national legislation resulted from the 1962 hearings. Therefore, in further considerations of possible use of coal slurry pipelines within and from the Northern Great Plains, legal studies should update available information on eminent domain.[11] As a practical matter, not much progress can be made in installation of pipelines to transport coal produced in this region without legislative action of each State through which the pipeline would pass. The precedent of the Black Mesa line does not assure similar treatment by other states than Arizona.

Installation of a coal slurry pipeline in the Northern Great Plains involves two other major problems, in addition to the legal problems referred to above and the problems of finance: providing the quantity of water required for the slurry; and providing a totally reliable source of electricity for operation of the pumping stations.

Transportation of coal by coal slurry pipeline is possible at lower costs than by unit trains, assuming movement of large quantities over long distances and over the extended periods of time necessary to justify such high capital investments.[12/] Pipeline costs are also less subject to inflation, and their use would result in a minimum of environmental disturbance.

The transportation of energy in the form of coal from the resource site, by pipeline or rail, to load centers has been found to have about the same costs as high-voltage electric transmission. This is illustrated by the following table from the Southwest Energy Study.[13/]

Comparison of Energy Transportation Costs

Item	Capacity	Capacity in 10^{12} Btu/day	Cents/million Btu/ 100 miles * Reported	Adjusted **
Coal Pipeline	3-15 million tons/year	0.2-1	1.3-3.8	3.2-9.5
Rail	70-100 tons/ car	-	4-6	10-15
Unit train	3 million tons annually	0.2	2.5	6.5
Electricity	600-1,000 mw	0.1	7-14	7-14

* At 10,000 Btu/kwh, the transportation cost per kwh is 1/100 of that shown.
** Adjusted for efficiency of generating plant at 40 percent.

Coal slurry pipeline systems up to 40 inches in diameter, with lengths of 1,000 miles or more are now being predicted.[14/] Such high volume pipeline systems represent a potential break-through in the development of low-cost transport of energy from the Northern Great Plains to Midwest and Southern markets.

References: Pipeline Transportation of Coal from N.G.P. States

1/ "Coal Slurry Pipelining in the Western United States", report by T.L. Thompson, Chief Slurry Engineer, and E.J. Wasp, Manager Slurry Systems - (Bechtel Incorporated, Pipeline & Production Service Division) presented at National Western Mining Conference, Denver, Colorado, February 5, 1971.

2/ Statement by Byron K. Smith, President & General Manager, Southern Pacific Pipe Lines Inc., January 1, 1971.

3/ News item appearing in THE CLEVELAND PRESS, November 6, 1961.

4/ "Transportation of Coal by Pipelines", address by J.P. Weir at Spring Meeting Of Coal Division, AIME, Price Utah. June 7, 1962.

5/ Report of the National Fuels and Energy Study Group to the Committee on Interior and Insular Affair, U.S. Senate. September 21, 1962. (p. 164)

6/ Statements by Edwin R. Phelps, President of Peabody Coal Co., at briefing of visitors on site of the coal slurry processing facilities of the Black Mesa Pipeline Company, Inc. (Subsidiary of Southern Pacific Pipelines, Inc.), May 1970.

7/ "Mining Coal On Black Mesa", Peabody Coal Company publication, November 1970.

8/ WEEKLY COAL REPORT NO. 2898, March 30, 1973. (pp. 7-14).

9/ "Legal and Legislative Aspects of Coal Pipelining", address by L. James Huegel before Section of Mineral and Natural Resources Law, American Bar Association. August 6, 1962.

10/ COAL SLURRY PIPELINE - Hearings before the Committee On Commerce, U.S. Senate, 87th Congress, 2nd Session, on S-3044. (246 pp).

11/ REPORT TO THE PANEL ON CIVILIAN TECHNOLOGY ON COAL SLURRY PIPELINES - Dept. of the Interior, May 1, 1962.

12/ ENERGY R & D AND NATIONAL PROGRESS - Prepared for the Interdepartmental Energy Study by the Energy Study Group under the direction of Ali Bulent Cambel.

13/ SOUTHWEST ENERGY STUDY, Appendix A. Part VI pp 13-14.

14/ "Slurry Pipelines - Energy Movers of the Future", abstract of paper by E. J. Wash and T. L. Thompson. The Oil and Gas Journal, Dec. 24, 1973.

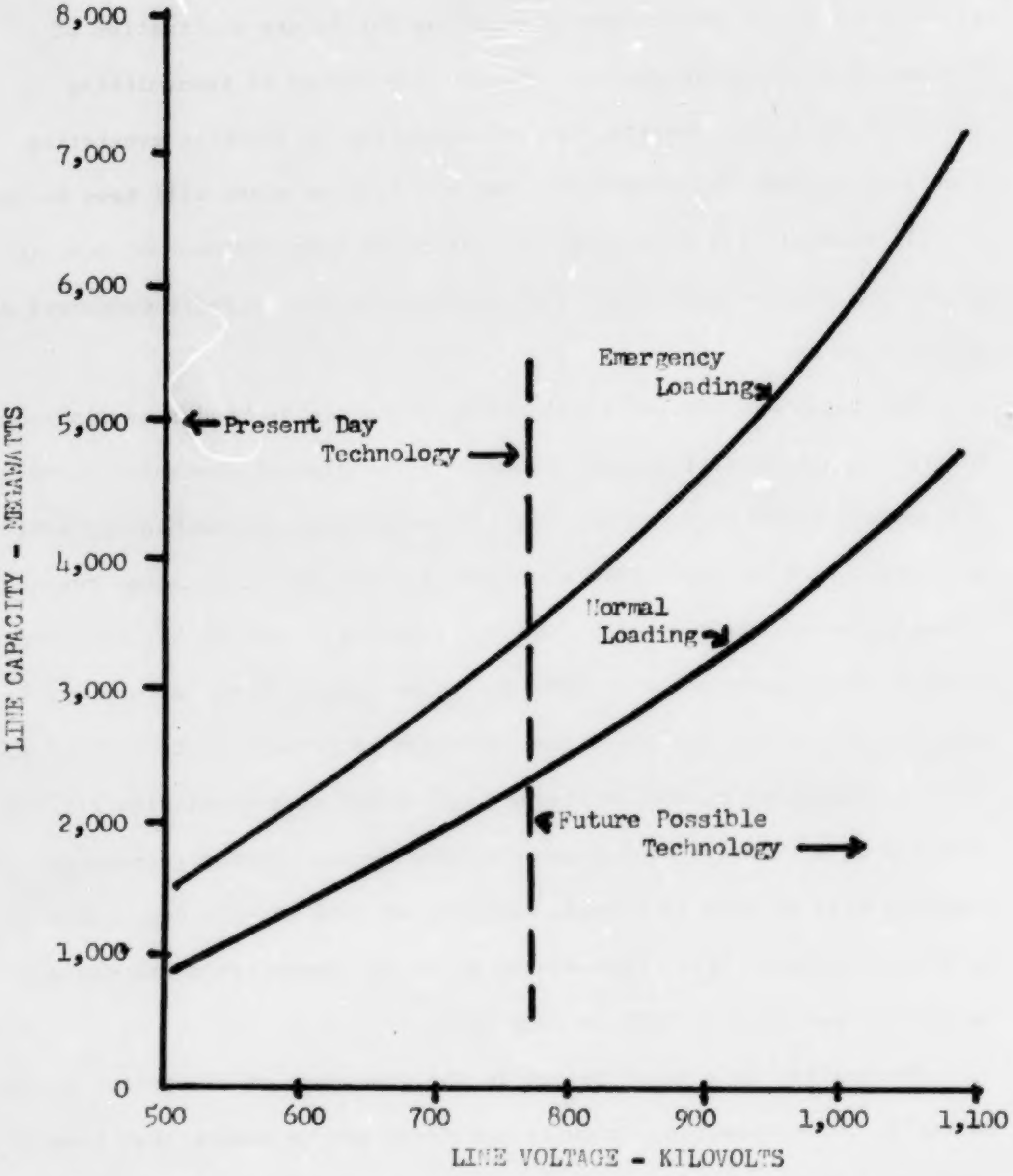
Transmission of Electric Energy

Transmission of electric energy from the Northern Great Plains (NGP) extra high voltage (EHV) and by ultra high voltage (UHV) lines is an alternative to consider in planning for future utilization of the region's energy resources. Use of this method of transmitting energy assumes that construction and operation of electric generating plants at or near the bituminous coal and lignite mines will have better overall economic and ecological justification than movement of coal to generating plants located at sites adjacent to the ultimate consumers of electric energy.

The magnitude of electrical energy to be transported from mine-mouth generating plants will require the use of the highest transmission voltage that modern technology can provide. The mid-seventies technology will have extra high voltage (EHV) equipment for use for alternating current (ac) transmission of 500,000 volts, 500 kilovolts (kV) and 765 kV; and direct current (dc) transmission of 1200 kV. More remote future technology is expected to provide equipment and knowledge to provide up to 1100 kV ac. Chart 1, appearing on the following page, shows ac transmission circuit capacity as a function of voltage. Future direct current technology probably will be able to provide circuits of 1600 kV with capacities up to 6000 megawatts (MW). With either ac or dc transmission the maximum capability per line is 5000 to 6000 MW.

Reliability is a major factor in the transport of electrical energy. Multiple, interconnected, circuits are necessary to ensure that loss of parts of a transmission line system due to storms or other damage does

Chart 1. - ALTERNATING CURRENT TRANSMISSION LINE POWER CAPABILITY



Source: Division of Power, Bureau of Reclamation, U.S. Dept. of Interior not cause black-outs. Generally, at least a three line system with geographic separation of lines is necessary to assure a high degree of reliability.

Assuming that mine-mouth generation is developed for a significant part of the energy produced from NGP coal, it is expected that the energy would necessarily be transported to widely diverse geographical areas. It is a reasonable expectation that electrical energy transport might be widely used within a radius of 500 miles and substantially used within a radius of 1000 miles, but for longer distances other means of transport seems more likely. This dispersion of load will tend to make the development of a reliable electric transmission system more difficult because of the fewer circuits going in the same direction, limiting the interconnections and resultant reliability. Futhermore, there will be the tendency to utilize less than the maximum technology, at least initially, to insure reliability and minimize costs. Therefore, it is expected that two or more voltage levels will be used and possibly both ac and dc technology.

Some possibilities of electric energy transportation from coal-fired generating plants in the Northern Great Plains are illustrated by the following five examples:

A. 10,000 MW - 600 to 900 miles - Four lines of 765 kV ac might be used to deliver mine-mouth generation to electric energy loads in an area between Minneapolis, Des Moines, Kansas City, and St. Louis. Depending upon the distribution of the load served, one line each on four separate corridors may be required from the mine-mouth plants. In addition, interconnecting lines between load centers would be required

B. 20,000 MW - 600 to 900 miles - Assuming an additional 10,000 MW delivery to the same load centers mentioned above, three to four additional 765 kV ac lines might be utilized. This could result in two lines on each of four corridors between mine-mouth plants and the load centers.

C. 40,000 MW - 600 to 900 miles - Assuming an additional 20,000 MW delivery to these same load centers and the existence of a 765 kV ac transmission system, this additional delivery might be accomplished with higher voltage transmission such as 1100 kV ac. Four 1100 kV lines, one in each of the four corridors mentioned above, might be found adequate for transport of this increment.

D. 10,000 MW - 300 to 600 miles - Eight or more 500 kV ac lines might be used to deliver mine-mouth generation to load centers in Colorado, Utah and eastern Idaho. Three corridors with two or three lines on each corridor might be used.

E. 10,000 MW - 900 to 1200 miles - For this long distance direct current technology might be found most appropriate, delivery of mine-mouth generation to the northwest coastal load centers of Seattle and Portland might be accomplished using two to four 1000 to 1500 kV dc lines on at least two corridors.

For transmission lines exceeding 100 miles in length, the average capital invested per mile in 1971 ranged from $6,966 to $456,105. As of June 30, 1971, the Bonneville Power Administration reported 11,482 miles of electric transmission lines having a total asset value of $999,622,263 and averaging

$87,060 per mile. Tennessee Valley Authority's 15,893 miles of transmission lines were reported as having a $972,435,517 total asset value, or an average of $61,186 per mile. 1/

Although the above averages are now historical and include electric transmission systems constructed over an extended period of years and with widely varying voltage levels and terrains, the experience of these two federal agencies gives a general indication of construction costs. More specific information on current electric transmission line construction and operating costs has been furnished by the Federal Power Commission. 2/ The construction costs and costs of the Jim Bridger step-up substation, are presented in Appendix V-B, "Transmission Line Data-FPC." In transmitting this construction cost information, it was explained that costs for the 345 kilovolt and 500 kilovolt lines are significantly greater than for the 230 kilovolt lines, and that this difference is primarily due to the use of metal supporting structures of greater height rather than the older wood construction employed for 230 kilovolt lines. It is expected that 345 kilovolt and 500 kilovolt lines will be used for the bulk transmission of electric energy, in the Northern Great Plains area over relatively long distances, to a greater extent than 230 kilovolt lines. Generally, the higher construction costs of the higher voltage lines will be more than

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1/ Statistics of Public Owned Electric Utilities in the United States - 1971, pp. 1-78

2/ Letter and tabulations from Bureau of Power, Federal Power Commission, November 26, 1973.

counterbalanced by their greater transmission capabilities.

No data was furnished be Federal Power Commission for direct current transmission lines, as they had no firm information relative to plans or proposals to use direct current transmission in moving electrical energy from the Northern Great Plains area. Furthermore, they were able to furnish only limited information on the annual operating and maintenance costs, and they were unable to rationalize the wide ranges indicated by the few examples reported. In one case, that of operating and maintaining the 230 kilovolt line running from Anaconda to Billings, Montana, the 1971 reported cost was $294.00 and only $20.00 in 1972.

Use of NGP coal by the electric utility industry can be accomplished through either of two generating plant siting alternatives. The coal can be burned at mine-mouth generating plants located in the NGP and the energy transported to densely populated load centers outside the area by high voltage transmission lines; or the coal can be moved out of the NGP to the population centers and burned in generating plant boilers located near the load centers. In the latter case, coal would be transported by unit trains or by coal slurry pipelines.

To illustrate the magnitude of projected coal-produced energy exports from the NGP and the relative impacts involved, estimates are furnished on the following page. The tabulation compares high voltage electrical transmission of energy from the NGP mine-mouth generating plants with transport of the same volumes of energy by means of unit trains or coal slurry pipelines.

ESTIMATED RELATIVE IMPACTS OF COAL-PRODUCED ELECTRICAL ENERGY EXPORTS FROM NGP

		LEVELS OF ELECTRIC GENERATION AND COAL REQUIREMENTS		
Means of Transport and Assumed Usage		335 million tons/yr. 1/ 80,640 MW Generation	167 million tons/yr. 2/ 40,320 MW Generation	83 million tons/yr. 3/ 20,160 MW Generation
SLURRY PIPELINE	100%	34 lines reqd.	17 lines reqd.	8 lines reqd.
(10 million tons/yr.	50%	17 " "	8 " "	4 " "
each line)	33%	11 " "	6 " "	3 " "
UNIT TRAINS				
Unit Train Trips/yr.	100%	33,500 trips	16,750 trips	8,275 trips
(10,000 tons/trip)	50%	16,750 "	8,375 "	4,187 "
	33%	11,167 "	5,383 "	2,792 "
Unit Train Trips/Day	100%	96 (4 per hr.)	48 (2 per hr.)	24 (1 per hr.)
	50%	48	24	12
	33%	32	16	8
No. of Unit Trains	100%	335 trains	168 trains	84 trains
Required	50%	168 "	84 "	42 "
(1000 mile traveled	33%	112 "	54 "	28 "
@ 3½ days/rd. trip)				
ELECTRICAL TRANSMISSION				
3,000 MW per 765 kW	100%	27 lines	14 lines	7 lines
line	50%	14 "	7 "	4 "
	33%	9 "	5 "	3 "
6,000 MW per 1100 kW	100%	14 lines	7 lines	4 lines
line	50%	7 "	4 "	not practical
	33%	5 "	not practical	" "

1/ Represents level projected under the high coal development scenario for year 2000.

2/ Represents one-half of level projected in preceding column.

3/ Represents one-fourth of level projected under high coal development scenario for year 2000, for earlier poin in time or slower rate of development. May be compared to 21 million tons/year and 5,180 MW generation projected for 1985 under high coal development scenario.

Source: Estimates by Division of Power, Bureau of Reclamation, U.S. Department of the Interior

In the illustrative tabulation, the lowest level of electric generation and coal requirements for which relative impacts were estimated and compared is nearly four times the 5,180 MW electric generation and 21 million tons of coal forecasted under the high coal development scenario. A single coal slurry pipeline, of the capacity assumed in the estimates, could transport one-half of the 21 million tons of coal. Alternately, one-half of that 1985 annual requirement could be moved by 10 unit trains; or the entire quantity moved by 20 unit trains. Transmission of the 5,180 MW of electric energy could be accomplished by less than 765 kW lines.

At present, unit trains and lower voltage electric transmission lines are the means used to transport coal-produced electric energy from the NGP area. These systems can be expanded to meet the 1985 requirements, possibly supplemented by a coal slurry pipeline.

Escalation of construction costs and costs of operation and maintenance has affected and will continue to affect all the methods of transporting energy. For unit trains, it is anticipated that generation of new capital investment will be their major problem. Mine-mouth generators and slurry pipelines will both face the critical problems of limited water supply in the mining area.

Looking beyond 1985 to the projected higher levels of electric generation and GNP coal requirements, the magnitude of energy movements from the NGP will rapidly approach a saturated condition. While the movements are now considered feasible and can be accomplished by various combined means of transport, extreme care will be needed in planning the siting of generating plants and selection of transport means as the export of coal-produced electrical energy moves up to and exceeds 50 million tons coal equivalent.

APPENDIX V-B

TRANSMISSION LINE DATA-FPC

TRANSMISSION LINE COST TABULATION

Date Source	Voltage (kV)	Conductor (MCM-ACSR)	Type Construction	Line Length (miles)	Line Costs Row ($/mile)	Line Costs Line Construction ($/mile)	Line Costs Total ($/mile)	Comple Dat
1/	345	2-795	Single circ. 2 pole-K	26.39	7,913	50,395	58,308	197
1/	345	2-795	Single circ. ST	17.40	-	56,696	56,696	197
2/	345	1-2156	10/	34.00	23,358	84,740	108,098	197
2/	345	1-2156	11/	82.90	9,681	64,215	73,896	197
3/	345	1-2156	Single circ. Alum. HF	64.00	5,663	57,780	63,443	197
4/	345	1-954	-	17.20	15,037	50,921	65,958	197
5/	230	1-954	Single circ. Wood HF	33.40	-	37,014	37,014	197
6/	345	-	Double circ. ST	-	-	-	130,000	197
7/	345	1-2183	Single circ. ST	525.	-	-	62,000	197
7/	230	1-954	Single circ. Wood HF	-	-	-	45,000	197
8/	345	-	Single circ. ST	-	-	-	110,000	197
8/	500	-	Single circ. ST	-	-	-	160,000	197
9/	345	-	Single circ. ST	-	-	-	90,000	197

1/ Northern States Power Co., 1972 Form 1

2/ Wisconsin Electric Power Co., 1972 Form 1

3/ Madison Gas & Electric Co., 1972 Form 1

4/ Omaha Public Power District, 1972 Form 1-M

5/ Minnesota Power & Light Co., 1972 Form 1

6/ Typical cost data received from Otter Tail Power Co. during 3/27/73 field trip.

7/ Cost data received from Basin Electric Power Coop. during 3/28/73 field trip.

8/ Typical cost data based on 1973 in-service received from United Power Assn. during 1/27/73 field trip.

9/ Typical cost data based on 1975 in-service received from Northern States Power Co. during 3/12/73 field trip.

10/ Approximately 50% steel pole and 50% Wood H-Frame.

11/ Approximately 80% Wood H-Frame and 20% steel pole.

Transmission Line Costs
in
WYOMING, IDAHO and MONTANA

					Line Costs					Annual O&M Costs	
Designation	Nominal Voltage kV	Number and size of conductors per phase	Type of Construction	Line length miles	R/W $/mi.	Line Construction $/mi.	Total $/mi.	Terminal Equipment Cost $	Date Completed or projected	R/W $/mi.	Line $/mi.
Idaho Power Co.											
Brady, Idaho to Antelope, Idaho 1/	230	1-1272 MCM ACSR	single circuit H-wood	58.84	1,868.	31,514.	33,382.	N.A.	1/70	N.A.	2,653.
Jim Bridger Plant, Wyo. to Naughton Jct., Wyo. 2/	345	2-1272 MCM ACSR	single circuit guyed delta aluminum towers	91.9	1,113.	48,640.	49,753. 3/	4/	12/73	N.A.	N.A.
Naughton Jct., Wyo. to Goshen, Idaho 2/	345	2-1272 MCM	single circuit guyed delta aluminum towers	133.8	2,425.	48,804.	51,228. 3/	4/	12/73	N.A.	N.A.
Montana Power Co.											
Anaconda, Montana to Billings, Montana 1/	230	1-1272 MCM ACSR	single circuit H-wood	222.8	1,892.	25,119.	27,012	N.A.	4/69	N.A.	20.
Hot Springs, Montana to Idaho Border 1/	230	1-1272 MCM ACSR	single circuit H-wood	274.1	2,199.	22,526.	24,725.	N.A.	12/69 5/	N.A.	1,551.
Hardin, Montana to Colstrip "A", Montana 2/	230	1-1272 MCM ACSR	single circuit H-wood	50.	2,440.	29,040.	31,480. 6/	N.A.	11/73	N.A.	N.A.
Billings-Great Falls 2/	230	1-1272 MCM ACSR	single circuit H-wood	180.	1,400.	30,028.	31,428. 7/	N.A.	11/74	N.A.	N.A.

1/ Obtained from 1972 FPC Form 1's
2/ Obtained from 1972 field visits
3/ 1973 price level
4/ Description and cost of Jim Bridger step-up substation attached.
5/ The 149.5-mile section Hot Springs to Anaconda placed into service 12/65 and Anaconda to Idaho Border section placed into service 12/69.
6/ 1972 price level
7/ 70-mile section 1973 price level, 110-mile section 1974 price level.

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PACIFIC POWER & LIGHT CO.
Transmission Line Costs in Wyoming

					Line		Costs			Annual O&M Costs	
Designation	Nominal Voltage kV	Number and size of conductors per phase	Type of Construction	Line length Miles	R/W $/mi.	Line Construction $/mi	Total $/mi.	Terminal Equipment Cost $	Date Completed or projected	R/W $/mi.	Line $/mi.
Dave Johnston Plant, Wyo. to Rock Springs, Wyo. 1/	230	1-1272 MCM ACSR	single circuit H-wood	231.98	292.21	32,351.63	32,580.84	N.A.	5/72	N.A.	N.A.
Jim Bridger Plant, Wyo. to Borah Sub, Idaho 2/	345	1-1272 MCM ACSR	single circuit steel tower	237	N.A.	N.A.	74,156.12 3/	4/	6/75	N.A.	N.A.
Jim Bridger Plant, Wyo. to Kinport, Idaho 2/	345	1-1272 MCM ACSR	single circuit steel tower	231	N.A.	N.A.	77,904.76 3/	4/	6/76	N.A.	N.A.

1/ Obtained from 1972 PP&L FPC Form 1.
2/ Obtained on 1972 field visit to PP&L main office.
3/ In service price level, escalation factor of 6 1/2% per year from 1972.
4/ Description and cost of Jim Bridger step-up substation attached.

JIM BRIDGER
Step-up Substation

Total cost - $12,465,000 - 1974-76 installation cost.

Substation: Description of Principal Equipment

Transformers

No.	Phase	MVA	Voltages	B.I.L.
3	3	561	345 KV/22KV	900/150
3	3	33	22 KV/7.2 KV/7.2KV	150/95/95
2	3	37	34.5 KV/7.2 KV/7.2 KV	200/95
2	3	200	345 KV/230 KV/34.5 KV	900/750/200
2	3	1.12	34.4 KV to 480 V	200/45

Power Circuit Breakers

No.	Type	Rating Voltage	Cont. Curr.	Interrupting MVA	B.I.L.
9	SFV	345 KV	2000 A	25000 MVA	1300 KV (Withstand
2	242GW40	230 KV	1600 A	40000 MVA	900 KV
4	345GS1500	34.5 KV	1200 A	1500 MVA	200 KV

Air Switches

No.	Type	Rating Voltage	Cont. Curr.	B.I.L.
18	DSB	345 KV	1600 A	1300 KV with GRD BLADES
6	DSB	345 KV	1600 A	1300 KV with GRD BLADES
3	VERT-BREAK	345 KV	1200 A	1300 KV with MOTOR MECH.
2	VERT-BREAK	345 KV	1200 A	1300 KV with MANUAL MECH.
3	VERT-REACH	345 KV	1600 A	1300 KV with MOTOR MECH.
4	DSB	230 KV	1200 A	900 KV
10	"V"	34.5 KV	1200 A	200 KV
1	VERT-BREAK	34.5 KV	1200 A	200 KV
1	"'"	34.5 KV	600 A	200 KV

Other Major Equipment

No.	Item	Type	Rating
3	Series Capacitor Banks	GE	345 KV/38 OHMs/1250 Amperes
3	Shunt Reactors	3Ø, 55 MVA	362 KV GRD 4/209 KV 900/110 BIL
1	Line Trap	"MW"	230 KV 1200 A
6	Coop. Cap. Pot. Device	"PCM"	230 KV 1050 KV BIL
9	Coop. Cap. Pot. Device	HI-"C"	345 KV 1550
3	Line Traps	265 mH	345 KV 1600 A
3	Current Transformers	"ACT"	230 KV 900 KV BIL

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PART VI.

ELECTRICAL GENERATION
DISCUSSION AND TECHNOLOGIES

Electrical Generation

As much of the coal from the Northern Great Plains (NGP) will be used under utility boilers it appears appropriate to discuss the whole subject of electrical generation. The following sections will discuss the electric utility industry, electrical generation using fossil fuels and geothermal, hydropower, and nuclear energy. Included in each discussion will be the problems associated with the use of each energy source in generating electricity. A discussion of advanced cycle systems will complete this section. The bulk of this discussion is based on a soon-to-be-published study prepared by the Bureau of Mines entitled

A. The Electric Utility Industry

Historical and projected trends of electric-power consumption

The overall demand for electrical power in the United States has shown extremely rapid growth in recent years. During the period 1950 through 1973 generating capacity, growing at an average annual rate of 8.5 percent, increased from 69 million kilowatts to million kilowatts, while total power consumption increased from 329 billion kilowatt hours to 1,884 billion kilowatt hours. Though increasing at a lesser rate, annual per capita consumption of electricity during the same period more than tripled.

The projections from 1973 to 1985 indicate that generating capacity will increase at an average annual rate of about 7 percent to 915 million kilowatts, while power consumption for the same period will increase to 4,140 billion kilowatt hours in 1985. During the same period, per capita consumption will more than double and increase to 17,020 kilowatt hours.

The historical and projected trends of power consumption in the United States are depicted in figure 1; detailed historical and projected statistical data on power generation are shown in Appendix VI-A, Table 1.

Historical and projected fuel requirements for utility use

During the period 1950-73 energy inputs to the electrical sector increased from 4,981 trillion Btu to 19,803 trillion Btu and coal's share of this market fluctuated between 45 percent and 53 percent. However, coal supplied virtually the same percentage of the fuel requirement for power generation in 1973 as in 1950.

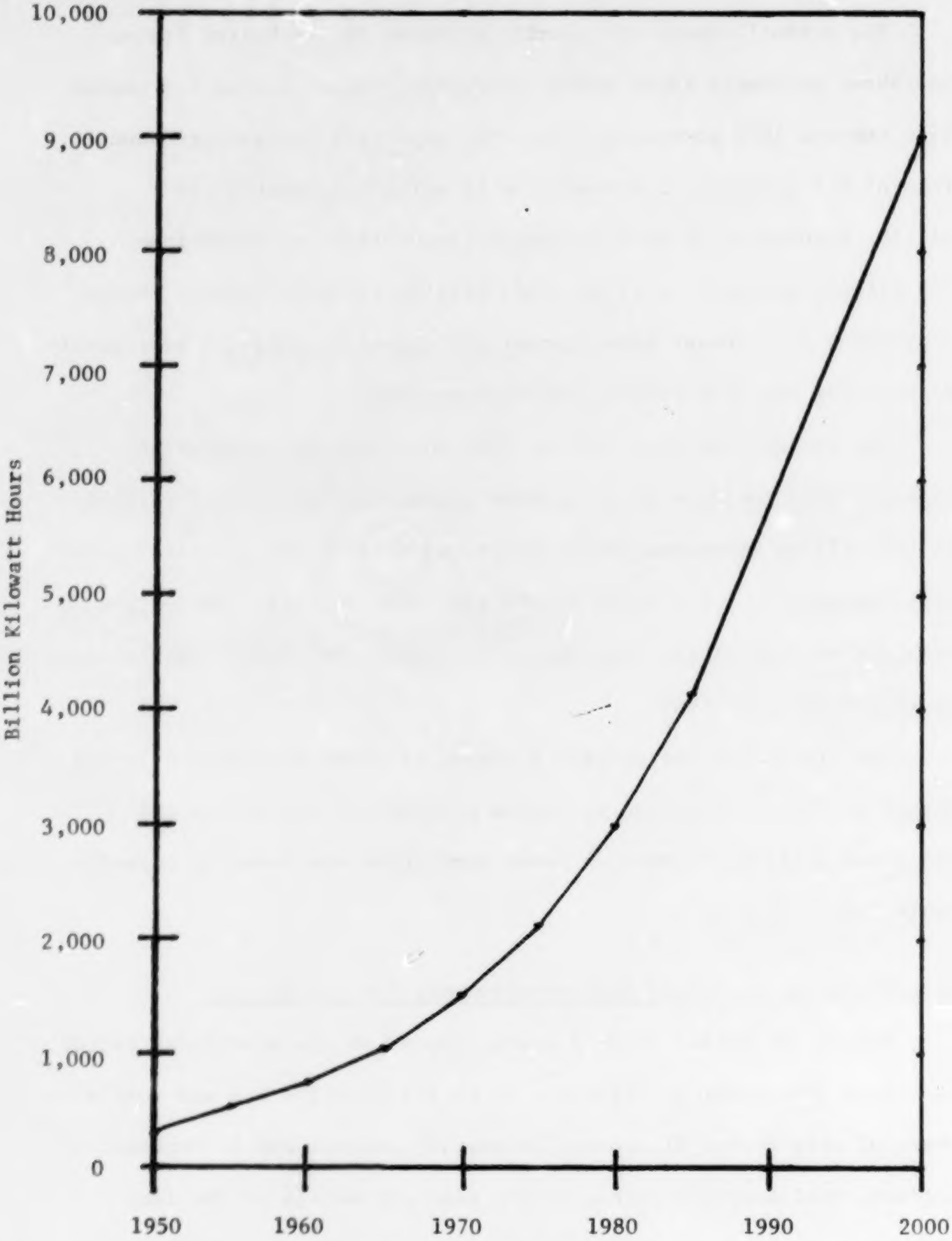


Figure 1 . U.S. Electric Power Consumption in Billion Kilowatt Hours, 1950-2000

Petroleum's share of the utility fuels market in 1973 increased above the 1950 level significantly, but the percentage of the total supplied by natural gas nearly doubled, while hydropower's percentage share declined by nearly one-half. Electric power derived from nuclear energy has been negligible to date; only 4.2 percent of the total energy for power generation in 1973 was nuclear derived.

Projections to 1985 indicate that there will be a decline in the percentage of the total utility fuel that coal will supply in the future, and natural gas and hydropower will also supply smaller portions of the total energy required for electric-power generation. Petroleum's share of the utility-fuels market will increase, however, and nuclear's share is forecast to increase to nearly one-third of the total by 1985. This was prior to the present (1973-74) petroleum crisis. It is felt that coal will retain a larger share of utility generation.

Despite the projected decline in coal's share of the utility-fuels market, coal requirements for power generation are forecast to increase from the 1973 level of 350 million tons to 613 million tons. In therm of total energy input, this amount of coal will supply 35 percent of the total utility fuels requirement, more than other energy sources, and about the same amount of energy that will be supplied by petroleum, natural gas, and hydropower combined.

The relative and quantitative energy inputs into the electrical sector are shown in figures 2 and 3. Detailed input data are shown in appendix table 2 .

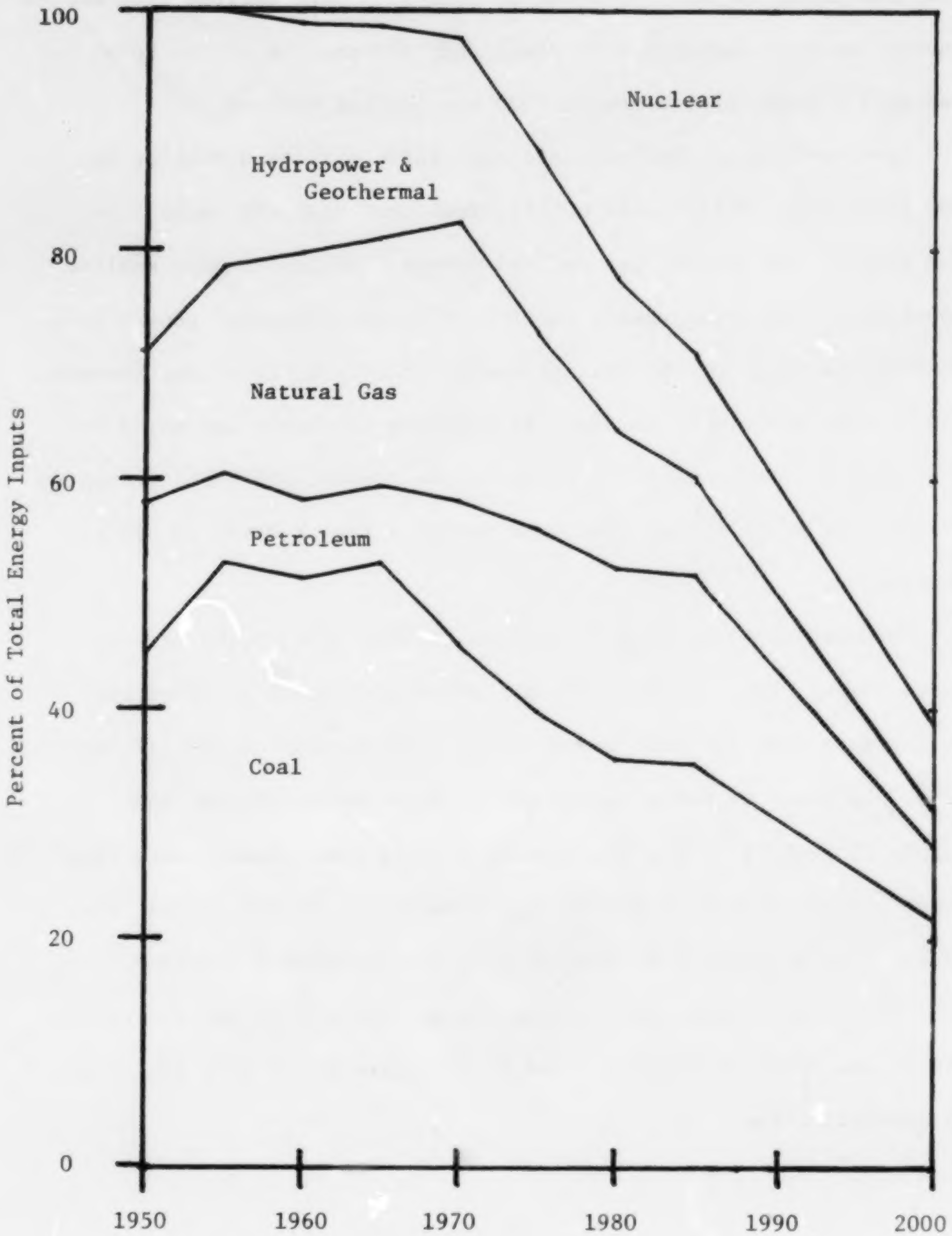


Figure 2 . Relative Energy Inputs to the Electrical Sector (in percentages) 1950-2000

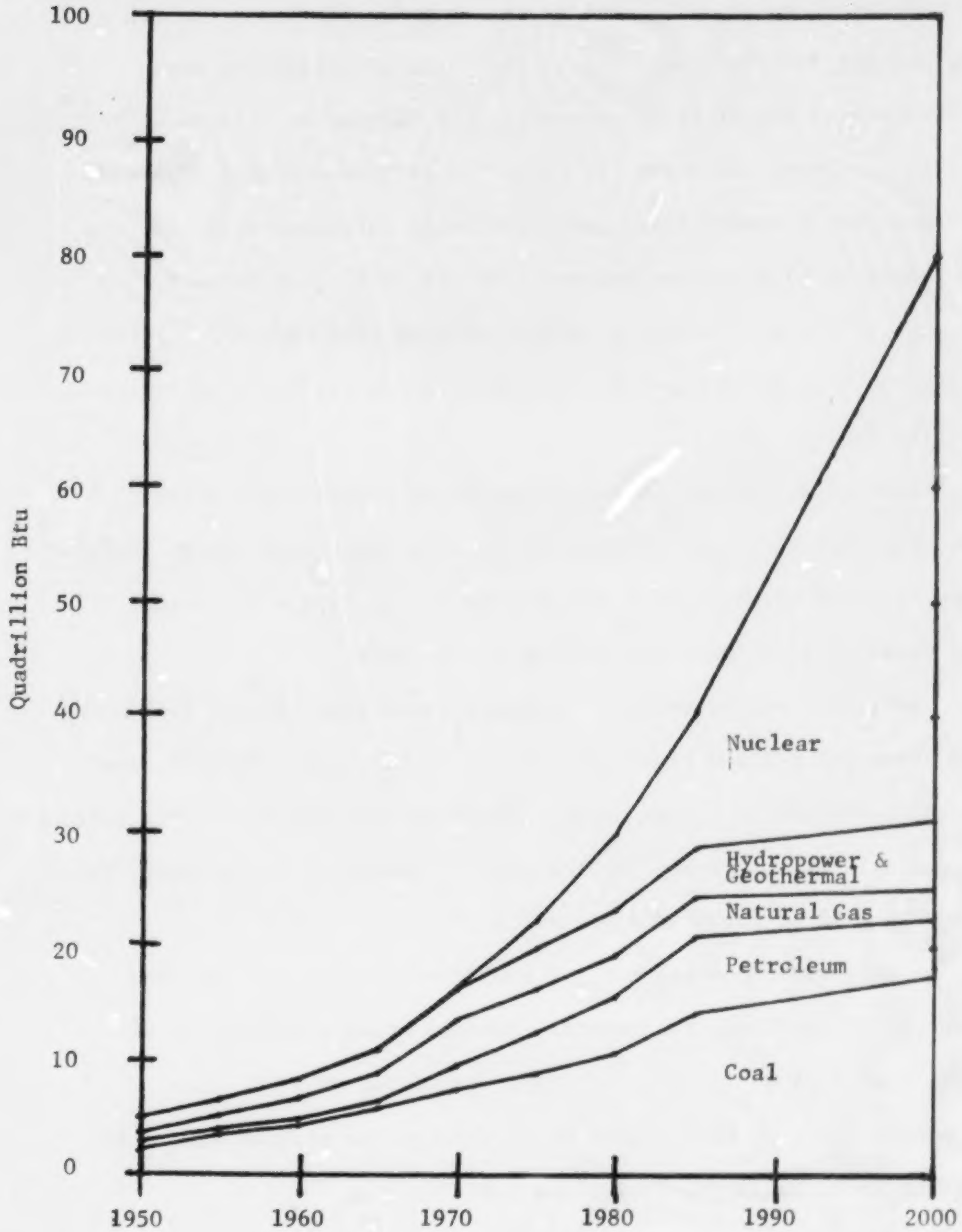


Figure 3 . Energy Inputs to the Electrical Sector by Major Source (in Quadrillion Btu) 1950 - 1970

Historical prices of utility fuels

Historical prices of utility fuels are illustrated in figure 4 and appendix table 3 . Prices are shown in the table on both a current and deflated basis but as the deflated prices are more indicative of actual price movements, the discussion will be limited to them. As shown, the price of petroleum products showed a consistent downward trend until 1969 when petroleum products increased by 13.1 percent between 1969 and 1970, 34.5 percent between 1970 and 1971, and 6 percent between 1971 and 1972. Petroleum prices in 1972 stand at 49.9 cents per million Btu for electricity-utility use.

Natural gas prices showed a consistent upward trend until reaching 27.7 cents per million Btu in 1962, when real prices trended down to a low of 24.2 cents per million Btu in 1969. Gas prices had risen to 25.7 cents per million Btu by 1972.

Real coal prices showed a downward trend from 1950 to 1968 when the price per million Btu reached a low of 25 cents. By 1971, coal prices had risen to a high of 31.8 cents per million Btu. This indicated an overall price increase for the 1968-71 period of 27 percent. The price in 1972 is 25.7 cents per million Btu.

A weighted composite cost of public utility fuels from 1950 through 1972 reflects the general downward trend of prices of the individual fuel up to 1968 and 1969. Beginning in 1969, the composite price in 1971 stands at 35.1 cents per million Btu, a 36 percent increase in the 1969-71 period.

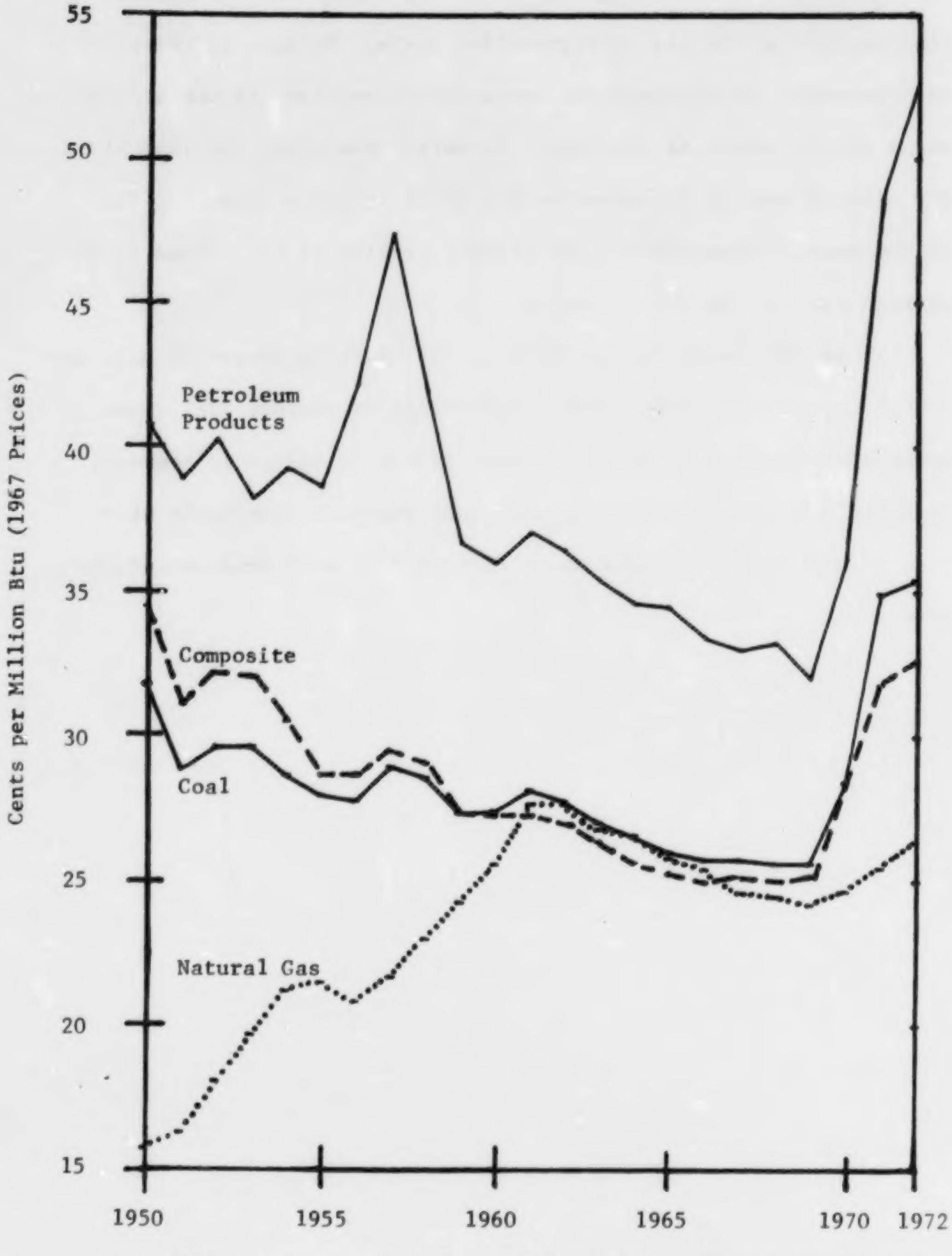


Figure 4 . Fossil Fuel Prices for Electrical Generation in Cents per Million Btu (1967 prices)

The recent price increases (1970-72) in electric-utility fuels can be attributed to a large degree to the impact of environmental restrictions on the use of high-sulfur fuels. Because of these environmental restrictions the competitive positions of the various fuels simply cannot be compared. No matter how cheap the fuel vis-a-vis other fuels, if it cannot be burned it is not a competing fuel. At the present time this is the primary problem of coal usage in the eastern part of the United States.

It is this inability to focus on the shifting target of environmental restrictions which makes projections of various fuel costs a meaningless exercise. The historical prices do indicate, however, that the price differential between coal and petroleum would allow coal to absorb considerable costs to render it more environmentally palatable.

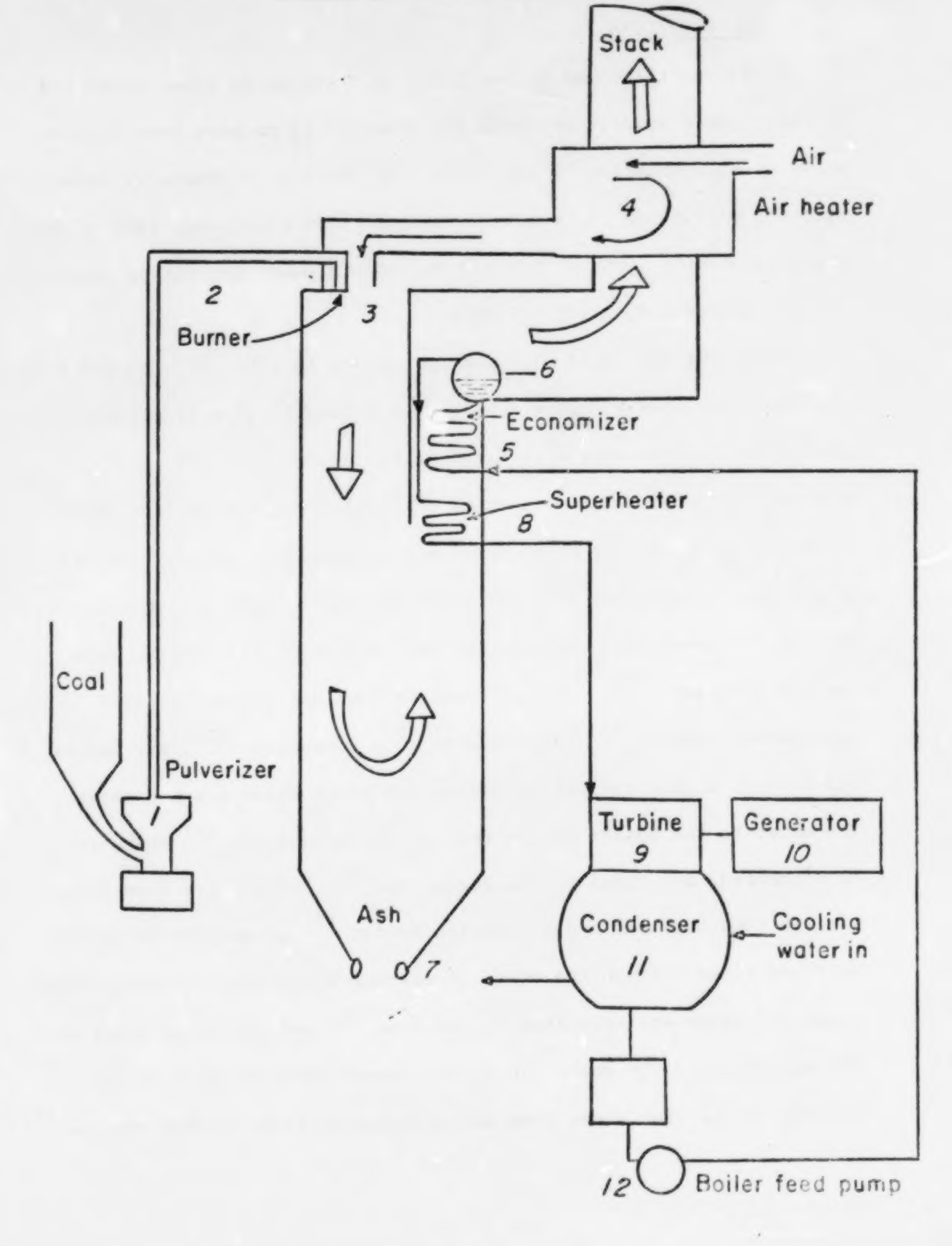
B. Power Generation Practice

Powerplant Operation

A modern boiler may be described as a system of tubes connected to one or more headers or drums and arranged to receive heat from the products of combustion of any fuel. The furnace is generally integral with the boiler and is usually formed of tubes comprising part of the steam generating system. Boilers for modern power generating plants are as tall as a 20-story building.

There are two fluid circulating systems in a boiler, the gas flow and the steam flow. Figure 5 shows a schematic of a simplified powerplant with a vertically fired boiler using coal. (Nuclear will be discussed under a separate heading) Other pulverized fuel-fired boiler types are front fired and tangentially fired. Coal is ground in a pulverizer, (1) and blown through burners (2) into the furnace (3) where it is mixed with hot combustion air flowing from the air preheater (4). The gas path through the boiler is first through the furnace (3), superheater (8), economizer (5), air heater (4), and through a dust collection system and stack which are not shown. The water to the boiler enters through the economizer (5) where it is preheated, and flows to the steam drum (6). The water then flows through downcomers to a distribution header (7) at the bottom of the unit and rises through the steam generating tubes into the steam drum. Steam and water are separated in the drum (6) and the steam flows to the superheater (8) where the steam temperature is raised to the desired level. The steam from the superheater flows to the turbine (9)

Figure 5. Powerplant Schematic Diagram


Stack
Air
Air heater
4
2
3
Burner
6
Economizer
5
Superheater
8
Coal
Pulverizer
1
Ash
7
Turbine
9
Generator
10
Condenser
11
Cooling
water in
12
Boiler feed pump

that spins the electrical generator (10). Steam from the turbine is condensed in the condenser (11). The condensed steam is collected in the bottom of the condenser and is returned to the boiler feed pump (12) that forces the water through the economizer to repeat the circulation through the system. The steam is condensed by large amounts of cooling water. Typical fuel and water requirements for a 1,000 MW (megawatt) plant are shown in table 13 .

Powerplant Size and Siting

In the past powerplants have been sited primarily from economical considerations. The plants have been located near load centers in order to minimize transmission line length and cost, transmission losses, and difficulties in acquiring rights-of-way. Adequate fuel supply, cooling water, area economics, tax base and local citizen attitude toward powerplants were all primary considerations.(34)

In recent years, there have been a number of developments thay have had a profound effect on traditional powerplant siting considerations. Perhaps the most important effect has been the rapid increase in size of the generating units and the trend toward increasing the number of generating units at a given location. Between 1900 and the 1930's the maximum size generation unit (single boiler) installed was less than 100 MW; this increased to 200 MW between 1930 and the mid-1950's. Late in the 1950's a large increase in the size of the units began and at present unit sizes of approximately 1,300 MW are under construction. In 1950, the average unit size place in service was 48 MW, (34) by 1960 the average size rose to 133 MW and, in 1971, over 55 percent of the new units on order exceeded 500 MW.

With the increase in the size and number of units installed at a site there is a comparable increased impact on the environment. The land usage for large sites is significant; for example, a 3,000 MW coal-fired steam generating system at a single site requires approximately 900 to 1,200 acres of land, and over a 35-year life produces enough ash to fill 300 to 400 acres of land to a depth of 25 feet.

By 1990, it is estimated that some 500 sites of 500 MW capacity or more will be required of which 250 will be new sites not yet selected. Advanced planning for sites for generating plants must be made to include an assessment of the future demands on air, water and land resources and to prevent or minimize adverse environmental impacts.

Base Load vs. Peak Load Units

The demand for power on an electrical generating system is not constant, it changes continuously, depending on the time of day and season. The bulk of the electricity is usually supplied with modern, high efficiency, base-loaded power generation units. The output from these units is reduced when the electrical demand is low. High loads on the system, usually of short duration, are supplied with older, less efficient, steam generating equipment. In some cases, turbines and diesel engines, operating at higher cost might be used in place of older equipment.

Importance of Reliability

As pointed out previously, the trend in powerplant construction is to install larger size generating units. These larger units represent a significant percentage of the capacity of a given system. An unscheduled outage of one of these large units might cause a serious power shortage since the reserve capacity of any power system has decreased below the reserve margin considered necessary to compensate for forced outages, plant maintenance, uncertainties in load forecasting and other reasonable contingencies.

C. Fossil Fueled Fired Powerplants

The major problems encountered in fossil fueled fired powerplants is the pollutants produced.

The actual contribution of fuel combustion in stationary sources to the total amount of emitted air pollutants can be seen in appendix VI-A table 4 (9), which shows the common pollutants and their origin for 1970. Identified total air pollutants for that year amounted to 264 million tons, of which 44.7 million tons are reported to have originated from fuel combustion in stationary sources. Of the three fossil fuels - coal, gas and fuel oil, coal is by far the major polluter. It accounts for the major portion of particulates and sulfur dioxide, and for about half of the nitrogen oxides. Appendix table 5 (9) gives typical concentration values for various stack gas components. It can be seen that concentrations may vary significantly depending on the type of boiler employed.

As coal is the major polluter, the remainder of this discussion will be based on coal. Coal as it is taken from the ground contains from 0.5 to 6 percent sulfur, either in inorganic (pyrite, FeS_2) or organic form (thiophene derivatives). The combustion of coal oxides the sulfur to sulfur dioxide (SO_2) and to a lesser extent sulfur trioxide (SO_3), which is then emitted from the stack gas. In coal combustion, the fixation of nitrogen and the oxidation of nitrogen contained in the fuel produce significant amounts of nitrogen oxides, usually expressed as $NO_x(NO + NO_2)$, although in stack gases the predominant species is NO. Furthermore, coal contains 6 to 20 percent ash, and in combustion, a significant fraction is entrained in the stack gases. Unless restrained, this ash is emitted to the atmosphere. Although coal combustion also produces trace amounts of other pollutants, the main pollutants are SO_2, NO_x and particulates.

Discussion of current pollution control follows.

Current Pollution Control Practices

Particulate Matter.

Particulate emissions from most coal-fired and some oil-fired utility boilers have been controlled for many years with mechanical collectors, electrostatic precipitators or a combination of both. In general, electrostatic precipitators are the most common control device. Although cyclone (mechanical) collectors can have a removal efficiency of as high as 80 percent, electrostatic precipitators can be designed to achieve 99.5 percent removal. With such collection efficiency, meeting EPA standards should be possible.

On the other hand, although removal efficiency for electrostatic precipitators is high, removal of particulate matter is dependent on factors such as particle size, carbon content, gas velocity, location and arrangement of components and sulfur content of the gas stream.(33) When low-sulfur fuel is used, or the carbon content of the fly ash increases, a marked reduction in collector efficiency can occur. This is due to an increased resistivity of the fly ash. In a limited number of cases, fabric filters are being installed after electrostatic precipitators to make up for this reduction. This application has just started (e.g. Arizona Public Service Company, Four Corners Plant) and may increase later. Fabric filters have not found wide application as yet, however, because of high operating cost, poor stability of bag material at stack gas temperatures and a relatively large pressure drop.

Other possible solutions to the low resistivity problem are lower stack temperatures, which increase moisture and SO_3 (sulfur trioxide) content and in turn decrease resistivity, and the use of hot-side electrostatic precipitators, which can still operate at high efficiencies with fly ash of high resistivity.

Wet scrubbers are receiving some attention as particulate control systems in cases where sulfur dioxide (e.g. wet limestone) removal systems are being considered. Wet SO_2 removal systems have the economic advantage of removing particulates as well as SO_2 and thus a significant savings can be made in the high capital costs of electrostatic precipitators. Some utilities are initially installing wet scrubbers for particulate control, with future plans for the addition of an SO_2 removal system.

Sulfur Dioxide (SO_2) Control

Tall Stacks.

Tall stacks are often employed to reduce the ground level concentration of air pollutants by permitting natural atmospheric turbulence to disperse them. The tall stack, however, has no capacity to reduce the total amount of material emitted to the atmosphere and it cannot guarantee preclusion of significant concentrations under all meteorological conditions. Many utilities, on the other hand, are using tall stacks of up to 1,000 feet in height. In the future, the tendency will probably be away from tall stacks to other methods of control. The use of tall stacks will in no way aid compliance with Federal emission standards, although they would aid in the ambient standards. As SO_2

stack gas control becomes commercially available, such control might be preferable.

Low-sulfur Fuels

Low-sulfur Coal

Many utilities are reducing SO_2 emissions by converting from high-sulfur to low-sulfur coal. In this situation, eastern electric utilities are in competition with metallurgical and export markets for low-sulfur coal and are paying premium prices for such fuel. There are ample reserves of low-sulfur coal in the Rocky Mountain Region, but the transportation cost is considerable. Even so, a number of utilities, Commonwealth Edison in Chicago, for one, are paying the extra costs, and low-sulfur coal is being delivered by unit train to utilities which are located far from the western reserves. Actually, the transportation charges for this low-sulfur coal are considerably more than the cost of the coal itself.

There are substantial reserves of coal in the west with a sulfur content lower than 1.2 lbs. SO_2 equivalent per million Btu. the present standard. Potentially then, western production could meet the total demands of the United States for a number of years, if mines were developed and transportation facilities were available.

Eastern low-sulfur bituminous coal reserves (those having 1.0 percent sulfur and less) although considerably less extensive, are still appreciable in quantity. However, much of this coal is unavailable for powerplant consumption since these reserves are largely tied up by long-term leases to steel companies for metallurgical purposes.

Natural-Gas and Imported Oil

Another means of controlling SO_2 from stationary fuel combustion, which is currently in use, is conversion to low-sulfur alternate fuels. The shortage of natural gas is too severe to allow for additional firing of powerplants with this fuel. This leaves low-sulfur fuel oil as the only practical alternative. The most important sources of low-sulfur oil are imports which come mostly from North Africa, and high-sulfur native and foreign oil that is desulfurized. A number of desulfurization plants are operating and significant increases are expected, especially in the Caribbean, where high-sulfur Venezuelan oil can be processed, prior to the recent embargo.

The trend towards large scale importation has been a necessary but reluctant move. Such action severely hampers effort to maintain a favorable balance of trade and also places a significant portion of the U.S. energy supply in the hands of foreign governments which may or may not be friendly to this country.

Pre-and Post-Combustion Sulfur Removal

Excluding the use of tall stacks, and changing to a low-sulfur fuel has either a limited advantage or increased economic cost, or possibly both. A more direct approach to SO_2 control would be the removal of sulfur from the fossil fuels prior to combustion or the removal of sulfur oxides from stack gases following combustion. However, following an exhaustive study of the situation, the National Academy of Engineers in 1970 (23) reported that, "... contrary to widely held belief, commercially proven technology for control of sulfur oxides from combustion processes does not exist." Today, three years later, at least 22 U.S. commercial size stack gas scrubbing processes for powerplants that have an estimated installation cost of over $200 million are in the design, construction or startup phase. Yet, at this writing, the NAE statement is still true since none of these 22 installations have been operated successfully on a large enough scale and over a period long enough to prove its commercial acceptability. (These installations are shown in Appendix VI-A, table6, The technology is discussed in Appendix VI-B.)

With only limited exception, the same situation holds true for the case of precombustion commercial sulfur removal from fossil fuels. The simultaneous removal of sulfur in the form of pyrite is incidental rather than primary and the potential increase in low-sulfur production possible through the crushing and physical removal of pyrite will convert only a small fraction of Eastern coals to the low-sulfur content necessary for Eastern powerplants.

Nitrogen Oxides (NO_x) Control Technology

Similar to the circumstances surrounding the technology of SO_x removal, the NO_x situation has not been resolved as yet on a commercial basis. Following a similarly exhaustive study NO_x emissions abatement, the National Academy of Engineers reported in 1972 (22). . . "With regard to combustion-control modification . . . control methods are not yet established for coal. . . No proven process is available (today) for substantial removal of NO_x from combustion stack gases."

Summary of Costs of Compliance

Utilization Costs

Accurate costs for air-pollution control can only be given for particulate removal systems, since they are the only systems that have been fully developed. For SO_2 and NO_x cost estimates only can be made, and this is a difficult and complex task. There are a myriad of uncertainties in economic analysis. In most cases, as one accumulates information by going from lab scale to bench scale and then to pilot plant, the projected capital and operating costs rise. More realistic operation often demonstrates unexpected problems which increase the basic process cost.

There is no doubt that air-pollution control is costly. As mentioned earlier, about $200 million is currently being spent on the development of SO_x control systems alone at over 20 different installations.(21) With capital cost estimates running as high as $70 per kilowatt for some processes, the capital cost for the construction of a $200 per kilowatt powerplant could increase by as much as 30 percent.

Particulate Removal

Out of all of the dust control systems described in the section on particulate removal, the one most commonly used is the electrostatic precipitator. It has a high efficiency, good dependability and few operating problems. Operating costs are relatively low and consist mainly of maintenance and power. Detailed cost studies on the control techniques for particulate air pollutants have been published by the United States Department of Health, Education and Welfare.(33)

Sulfur Dioxide Removal.

The latest cost estimates for the wet limestone SO_2 control process are excellent examples of the rapid rise in costs. In 1969, the estimated capital cost for a plant burning 3.5 percent sulfur coal was under \$7 per kilowatt for a new 1,000 MW unit and \$13 per kilowatt for a 200 MW existing plant.(30) In 1972, the estimate had risen to over \$40 per kilowatt(29) for a new plant, and the actual cost of retrofitting the TVA Widows Creek 550 MW unit is now approaching \$70 per kilowatt.(15) Although inflation itself would cause the estimates to rise, the major increase is due to more realistic experimentation which dictated a more complicated process design and plant. Figure 5 gives an indication of how the costs have been changing for the limestone process over the years.

Many factors affect capital and operating costs of the proposed control schemes described in appendix B. Most important are the size of the powerplant, new plant versus retrofitting (retrofitting is more expensive), sulfur and ash content of the fuel, pollution control requirements, price of reactant for the process, solid waste disposal constraints and type of scrubber (packed tower, Venturi, etc.).

Estimated capital and operating costs for the more important SO_2 control processes are as follows:

Process	Capital Cost c/million Btu	Operating Cost c/million Btu	Total Cost c/million Btu
Wet Limestone	7-13	4-10	11-23
Magnesium Oxide	9-16	7-15	16-31
Cat-Ox	11-17	5-10	16-27
Wellman Power Gas	10-17	6-13	14-30

(Based upon the assumption of an 18 percent capital cost, 75 percent load factor and a heat rate of 10,000 Btu per kilowatt hour.)

Appendix table 7 gives a summary of some estimated capital and operating costs for SO_2 control processes on a kilowatt basis.(26) The estimated costs are based upon a coal sulfur content of approximately 3.0 percent.

Although some of the processes are designed to produce a saleable byproduct, credit is not given in the table because of the uncertainty concerning byproduct economics. If large numbers of powerplants begin producing byproduct sulfur products (the most common are sulfuric acid and sulfur), many market areas will be glutted and the materials will have to be stored.

The operating cost for a coal-fired powerplant without SO_x removal approximates 8.0 mills per kilowatt hour, of which 3 mills per kilowatt hour are attributable to fuel costs. Therefore, assuming acceptable operability of the wet limestone scrubbing process, cumulative costs that include coal firing and sulfur-oxides removal then become 3.7 to 4.5 mills per kilowatt hour. This represents a cost increase of 23 to 50 percent above that of the fuel. Based on a fuel cost of $0.24 per million Btu assuming coal at $6.00 per ton, the cumulative cost of fuel plus wet limestone scrubbing for SO_x removal, including capital costs, will range between $0.35 and $0.47 per million Btu. Similarly, cumulative costs for fuel and MgO sulfur-oxide removal will be in the range of $0.40 to $0.55 per million Btu, while cumulative costs for fuel and catalytic oxidation SO_x removal will approximate $0.40 to $0.51 per million Btu. For Wellman-Lord, the estimated cost is $0.38 to $0.54 per million Btu.

Nitrogen Oxides.

The two major schemes of control for nitrogen oxides are stack-gas removal and combustion modification. Nitrogen-oxide stack-gas removal is not at the same stage of development as sulfur-oxide removal and, therefore, the cost estimates are considerably more uncertain. Some cost estimates have been given but they are based on unproven processes and, thus, cannot be considered reliable.(5)

Little has been done in testing combustion modification techniques with large coal-fired systems and, therefore, cost estimates for implementing such changes are difficult to make. Some preliminary estimates are, however, available for such techniques.(29) For new units the choice of a specific boiler type designed for low NO_x emission would result in negligible additional cost.

Resulting Power Cost.

The average price of electricity, after dropping for a number of years, has begun to rise. Inflation, particulate air-pollution control and increased fuel cost, especially for the low-sulfur varieties, all are contributing to recent price increases. It is difficult to estimate how the cost of SO_2 and NO_x control will affect consumer electric bills because of the uncertainty of the economics of such control. There is also a question of how much of the added cost will be transferred to the consumer. However, if an assumption is made that there will be a cost of 2 mills per kilowatt hour for operating cost and capital charges for SO_2 control and that such a cost will be transferred directly to the consumer, then the increase would be about 10 percent, based upon the 1971 average price of electricity.

Total Costs.

The total cost of all coals burned by utilities in 1970 averaged $0.31 per million Btu, or about $7.24 per ton. With implementation of the potential items of cost increase (reclamation, health and safety, and SO_2 removal systems), it has been estimated that the full cost of coals burned at utilities, in 1970 dollars and excluding taxes, will range between $0.47 and $0.71 per million Btu, or from $10.91 to $16.48 per ton in 1985. The cost ranges for 1975 and 1980 have been estimated at $0.37 to $0.41 and $0.41 to $0.56 per million Btu, respectively. This includes a weighting factor since not all powerplants will need SO_2 control systems and not all mines will incur the same health and safety and reclamation costs.

D. Nuclear Powerplants

General 1/

As of the end of 1972 there were 15,300 megawatts (MW) of installed nuclear power capacity. The power inputs to these plants represented 3.1 percent of the 1972 energy inputs to the electrical sector. In addition, the electrical generating capacity of nuclear plants under construction and on order already exceeds an additional 125,000 MW. These powerplants are commonly over 1,000 MW electric capacity each, and take from 8 to 10 years from inception to commercial operation.

The dominant nuclear reactor powerplant in this century will be the light-water-cooled reactor (LWR). These plants derive their heat primarily from fissionable uranium isotope U^{235}. The U^{235} content of natural uranium is 0.7 percent. The remainder of natural uranium is the isotope U^{238}. The U^{235} content of uranium must be enriched to fuel LWR's as well as the high temperature gas reactors (HTGR) which are also being used.

When breeder reactors come into general use (tentatively scheduled for 1986), they will initially utilize plutonium generated from the uranium isotope,U^{235} accumulated during uranium enrichment will be one source of U^{238}. The plutonium surplus to operating breeders will fuel new breeders.

1/ This discussion is based on WASH-1242, Nuclear Fuel Supply, AEC May 1973.

Nuclear Power Forecasts

The nuclear power forecast for the United States through 2000 is as follows: 2/

Year	Installed capacity	Incremental capacity (MW)	Cumulative Capital requirements (billion $) *
1972	15,300	-	-
1975	50,887	35,587	14.24
1980	123,864	72,977	47.42
1985	215,000	91,136	83.87
2000	960,000	745,000	381.87

* Based on $400/kw of installed capacity. Higher capital costs/kw will require correspondingly higher cumulative capital requirements.

This capacity in 2000 will account for 51.1 percent of total capacity, and 60.7 percent of total net generation.

2/ Based on "U.S. Energy Through the Year 2000," Dept. of the Interior, December 1972. Rounding off not performed.

Uranium Requirements

A typical LWR of 1,000 MW electric capacity needs enriched uranium produced from 550 to 625 tons of uranium oxide (U_3O_8) for initial loading. Refueling will require about 200 tons of U_3O_8) per year. Recycling of plutonium recovered from the spent reactor fuel elements could reduce annual makeup requirements to about 170 tons of U_3O_8.

Breeder reactors can expand the energy derived from natural uranium and hence will reduce uranium demand. The approximate expansion is about 60 to 1, i.e., one ton of uranium will produce approximately 60 times as much electricity when used in a breeder as when used in a LWR.

U_3O_8 requirements for the attainment of the capacity indicated for 2000 are as follows (in thousands of short tons): 3/

Year	Annual requirements	Cumulative requirements
1972	4.6 *	4.6
1975	18.3	43.4
1980	36.0	182.5
1985	54.4	414.7
2000	122.1	1,791.4

*Estimate

3/ Data partially based on "Nuclear Power, 1973-2000," U.S. Atomic Energy Commission, Dec. 1972, and partially on "U.S. Energy Through the Year 2000," Dept. of Interior, Dec. 1972. Enrichment plant tail assays at 0.30 percent U^{235}. Recycle of plutonium in reactor loadings beginning with 25 percent in 1977, 75 percent in 1979, and as much as possible thereafter, without limiting LMFBR construction.

Uranium Enrichment

U^{235} in the uranium used in light-water-reactors (LWR) must be enriched from the normal content of 0.7 percent to about 3 percent. The enrichment used for high-temperature gas-cooled reactor (HTGR) is about 90 percent. A stream or tail, of depleted uranium (lower than normal U^{235} content) is also produced by the enrichment plant.

Possible annual United States enriching requirements, measured in separative work units (SWU), to the year 2000 are shown in the following tabulation (all requirements in thousands of units) 4/

Year	Annual SWU requirements	Cumulative SWU requirements	Cumulative Cost (billion $) *
1972	1,600 **	1,600	.05
1975	6,400	15,000	.48
1980	14,400	69,200	2.21
1985	23,000	165,400	5.29
2000	59,400	802,700	25.69

* Based on $32/SWU
** Estimate

Slippages in the breeder reactors coming on line would increase the necessity for new enrichment plants.

4_/ Data partially based on "Nuclear Power, 1973-2000," U.S. Atomic Energy Commission, DEC. 1972. Enrichment plant tail assays at 0.30 percent U^{235}. Recycle of plutonium in reactor loadings beginning with 25 percent in 1977, 75 percent in 1979, and as much as possible thereafter, without limiting LMFBR construction.

Resource Adequacy

Table 8 of Appendix VI-A indicates U.S. Uranium Resources as of January 1, 1973, for use in nuclear reactors. There are 967,000 tons of U_3O_8 available at a cost of $8/lb of U_3O_8. If the price is allowed to rise to $15/lb. of U_3O_8 then 1,764,000 tons will be available. (The two figures are not additive as the $8/lb. figure is subsumed in the $15/lb. figure).

Less uranium has been needed in the last few years than expected so that the industry now has excess production capacity, large inventories and low prices - a situation expected to change as requirements grow. A study made by the Atomic Energy Commission indicates that the annual production rate from presently estimated $8 resources could be increased to about the level of demand for the 1979 intermediate case. Subsequent needs might be met from known resources for a few years if special efforts were made, but then new, low-cost resources would be required. With adequate lead time, higher cost resources could be exploited.

There is, of course, some desirable resource levels. The Atomic Energy Commission points out:

> "However, the time required to find new ore, construct new mines and mills, amortize investments and permit contracting for deliveries to consumers over a reasonable period of time in the future indicates the need for an ore reserve equal to at least the following eight years' requirements. In addition, analyses of production capability suggest that a reasonable total resource level (ore reserves plus potential resources) may be about four times the requirement of the following seven years." 5/

5/ WASH-1242, Nuclear Fuel Supply, AEC, May 1973, p.6.

Low grade material corresponding to a production cutoff cost of \$15 or more per pound of U_3O_8 may well have to be mined eventually to meet requirements. The sooner the breeder reactor comes in the less the requirement for high priced ores - if the breeder performs as advertised. (There are some indications that the doubling time for the breeder may well be 18-24 years as compared to the 10 years assumed in economic-technical-feasibility studies. Fuel requirements would rise more as resort to higher priced fuels would be required.) 6/

Fusion 7/

The outlook for fusion power is brighter than in the past, but the scientific feasibility remains undemonstrated. The Soviet experiments with their Tokomak machine revived hopes that the technical conditions for a useful controlled nuclear reactor could be achieved. This has led to a flurry of experimental activity in the U.S. duplicating Soviet results. Whether a controlled reactor can be reliably demonstrated remain speculative. However, there are four reasons for pursuing fusion:

1. The possibility of unlimited low cost fuel in the form of deuteruim from sea water.
2. The inherent safety against runaway reactions.
3. Manageable radioactivity problems.
4. High thermal efficiencies.

There is considerable doubt that nuclear fusion could be available in this century under any scenario. There are four major phases in

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6/ "Increased Doubling Time, Rising Costs, Lowers Breeder Reactor Prospects," Energy Digest, Nov. 16, 1973.

7/ The following discussion is based on Energy Research and Development, Report of the Task Force on Energy of the Subcommittee on Science, Research and Development of the Committee on Science and Astronautics, U.S. H.R. 92nd Congress, 2nd Session, pp. 116-120.

the development of fusion power:

1. A basic plasma physics research and development phase.
2. A proof of scientific feasibility phase.
3. An experimental reactor phase; and
4. A working prototype or demonstration phase.

Work at present is only entering the second phase, and completion of all phases does not appear feasible in this century barring an unexpected breakthrough. For this reason fusion power has not been factored into this forecast.

E. Hydropower and Tidal Power

Hydropower

Hydropower is, in a sense, solar power for it represents that fraction of solar power concentrated by the circulation of water during the hydrologic cycle. The potential of any site is a function both of stream discharge and the height of fall, hence the better hydroelectric sites are concentrated in areas with heavy rainfall and large topographic relief. Table 9 in the Appendix entitled Hydroelectric Power Resources of the United States by Geographic Divisions, shows United States potential hydropower, capacity, and the extent to which it is developed.

As of December 31, 1972, some 56,566 megawatts (MW) of capacity had been developed. This represents 31.6 percent of the total United States hydropower capacity. From an energy standpoint this capacity can produce 272,733 million kilowatt hours (KWhrs) per year of energy or some 38.8 percent of the total potential electrical production from hydropower. This indicates the United States has selected its best sites for development first and that future development will not allow increases in electrical production per unit of capacity as high as those experienced in the past.

The undeveloped capacity left is 122,041 MW (or 68.4 percent of total potential capacity), and the capacity for electrical production left undeveloped is 428,773 million KWhrs per year (or 61.2 percent of the total annual production potential). Of this undeveloped potential approximately 32,600 MW of capacity and 173,000 million KWhrs per year of production potential is located in Alaska. Sparsity of population and remoteness from those population centers with large energy requirements, rules out Alaskan potential as economically impractical. Additionally, the Wild and Scenic Rivers Act (PL 90-542) named 27 river systems that are to be studied for possible inclusion in the national wild and scenic river system.[1] These separate streams include potential capacity of 7,000 MW and potential generation of approximately 24,400 million KWhrs. Deducting these figures, and Alaskan potential from our undeveloped potential leaves us approximately 82,440 MWs of capacity and 404,200 million KWhrs of potential generation to develop.

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[1] PL 90-542 also designated 8 rivers with a potential capacity of 1,419 MW as wild and scenic rivers. This capacity is not reflected in any figures herein. A discussion of this aspect of hydropower may be found in Federal Power Commission, Hydroelectric Power Resources of the United States, Developed and Undeveloped, Jan. 1, 1972, p.XV

Forecast Hydropower

The forecast is based on a Federal Power Commission forecast [2] to 1990 extrapolated to 2000. It indicates an increase in hydropower electrical capacity from 56,566 MW in 1972 to 91,000 MW in 2000, while total generation rises from 272,734 million KWhrs to 393,000 million KWhrs. Details are illustrated in Table 10 of Appendix VI-A.

Thus hydropower capacity is expected to increase by 34,434 MW and generation by 120,866 million KWhrs between 1972 and 2000. This would leave undeveloped in the contiguous 48 States some 50,000 MW's of hydropower with a potential ability to generate approximately 283,300 million KWhrs.

Based on an average cost of $300 per KW of installed capacity this increase envisaged will cost approximately $10.33 billion by 2000. Table 11 in the appendix shows cumulative costs over the period 1972-2000.

There are numerous caveats to the development of the hydropower resources that will be left in the 48 contiguous States. There are hundreds of individually identified sites, and the estimates of conventional undeveloped water power aggregates the potential of these sites. As pointed out by the Federal Power Commission in its evaluation of hydroelectric resources:

> "The possibility of developing a particular site depends on engineering, economic, environmental and other considerations which may vary considerably over time. Most sites included in this report have shown indications of engineering feasibility. Some of them have evidenced economic feasibility as well. Many sites have not been analyzed in sufficient detail to evaluate their economic or environmental costs and benefits but are included to give the reader an indication of the upper limit of the conventional water power potential of the

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[2] Federal Power Commission, "The 1970 National Power Survey, Part 1," pp 1-7-24, 25.

United States. The estimates have been adjusted from previous years and will continue to be revised to reflect engineering, economic or other changes as they occur. It should be recognized, however, that economic and other factors may preclude the development of many of the potential sites listed." 3/

To this must be added the necessity for consideration of environmental impacts.

Regional Hydropower

The Northern Great Plains has a potential hydropower capacity of 12,690 MW with the ability to generate 49,677 million KWhrs of electricity annually. Of this capacity 22.5 percent is developed, and of the generation potential some 33.6 percent has been developed. Full details are shown in Table 12 of Appendix VI-A.

Tidal Power

Tidal power is similar to water power except that it is derived from the alternate filling and emptying of a bay or estuary that can be enclosed by a dam. According to L. B. Bernstein in his book, "Tidal Energy for Electric Power Plants," there are two major potential tidal power sites available to the United States. One is the Bay of Fundy with nine sites, including many on the Canadian side, and an average potential power capacity of approximately 29,000 MW. The other site is Ternagain Bay in Cook Inlet, Alaska, with a possible potential power capacity of 9,500 MW. Population sparsity in the area makes the Ternagain Bay project economically impractical. Assuming

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3/ Federal Power Commission, "Hydroelectric Power Resources of the United States, Developed and Undeveloped," Govt. Printing Office, Jan. 1. 1972, p. XIV the U.S. has use of half the Bay of Fundy capacity (and Canada the other half), then the total addition to U.S. capacity that is remotely useful would be approximately 15,000 MW. This would represent approximately 0.8 percent of our generating capacity needs by 2000. Under no circumstances is it envisaged that tidal power will make any significant contribution to U.S. energy needs between 1972 and 2000.

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APPENDIX VI-A.

ELECTRICAL GENERATION DATA

VI41a

Table 2. Energy inputs to the electrical sector for selected years, 1950-70 actual and projections to 2000 1/

	1950	1955	1960	1965	1970	1975	1980	1985	2000
Coal									
Million short tons	91.9	143.8	176.6	244.9	322.4	384	460	613	755
Trillion Btu	2,228	3,482	4,251	5,843	7,483	8,900	10,660	14,220	17,520
Percent of total	44.7	52.8	51.4	52.8	45.5	39.7	35.6	35.2	21.8
Petroleum									
Million barrels	106.3	81.9	90.1	118.6	333.8	573	800	1,064	807
Trillion Btu	662	512	564	744	2,087	3,580	5,000	6,650	5,040
Percent of total	13.3	7.8	6.8	6.7	12.6	16.0	16.7	16.5	6.3
Natural Gas									
Billion cubic feet	628.9	1,153.3	1,724.8	2,318.3	3,894	3,686	3,492	3,346	2,561
Trillion Btu	651	1,194	1,785	2,392	4,015	3,800	3,000	3,450	2,640
Percent of total	13.1	18.1	21.6	21.6	24.4	17.0	12.0	8.5	3.3
Hydropower									
Billion Kwhrs	102.7	120.3	154.0	196.8	252.2	350	420	470	700
Trillion Btu 2/	1,440	1,407	1,657	2,058	2,650	3,570	3,990	4,320	5,950
Percent of total	28.9	21.3	20.1	18.6	16.1	15.9	13.3	10.7	7.4
Nuclear Power									
Billion Kwhrs	-	-	.5	3.7	21.8	240	630	1,130	5,470
Trillion Btu 3/	-	-	6	38	229	2,560	6,770	11,750	49,230
Percent of total	-	-	.1	.3	1.4	11.4	22.4	29.1	61.2
Total									
Trillion Btu	4,981	6,595	8,263	11,075	16,464	22,410	29,970	40,390	80,380

1/ Actual data from Division of Fossil Fuels, Bureau of Mines. Projections based on "U.S. Energy Through the Year 2000," Dept. of Interior, 1972.

2/ Based on conversion of Kwhr output at prevailing heat rate for fossil fuel fired steam plants.

3/ Based on conversion.

Table 1. U.S. Electric utility power statistics for selected years (on a population, capacity, and consumption basis), 1950-70 actual, and projections to 2000 1/

	1950	1955	1960	1965	1970	1975	1980	1985	2000
Population	152.3	165.9	180.7	194.2	204.8	216.2	229.4	243.3	279.7
Generating capacity (millions of Kw)	68.9	114.5	168.0	236.1	340.4	480	660	915	1,880
Kilowatt capacity per capita	.45	.69	.93	1.22	1.66	2.22	2.88	3.76	6.72
Power consumption (billions of Kwhrs)	329.1	547.0	753.4	1,055.0	1,524.8	2,130	3,000	4,140	9,010
Annual per capita consumption (Kwhrs)	2,161	3,297	4,169	5,433	7,469	9,850	13,080	17,020	32,210

1/ Actual data from Division of Fossil Fuels, Bureau of Mines. Projections based on *U.S. Energy Through the Year 2000*, Department of the Interior, 1972.

Table 3. Fossil fuel prices for electrical generation in cents per million Btu, 1950-71
(in both current and 1967 prices)

Year	WPI 1/	Petroleum products		Natural Gas		Coal		Composite	
		Current	Deflated	Current	Deflated	Current	Deflated	Current	Deflated
1950	78.0	31.8	40.8	12.3	15.8	26.9	34.5	24.8	31.8
					1				
1951	86.1	33.5	38.9	14.0	16.3	26.8	31.1	24.9	28.9
1952	84.1	33.9	40.3	15.2	18.1	27.1	32.2	25.0	29.7
1953	84.8	32.4	38.2	16.7	19.7	27.1	32.0	25.2	29.7
1954	85.0	33.4	39.3	18.0	21.2	25.9	30.5	24.4	28.7
1955	86.9	33.5	38.6	18.7	21.5	24.9	28.7	24.3	28.0
1956	90.8	38.3	42.2	18.9	20.8	26.1	28.7	25.4	27.8
1957	93.3	44.2	47.4	20.2	21.7	27.5	29.5	27.1	29.0
1958	93.6	39.2	41.9	21.5	23.0	27.2	29.1	26.8	28.6
1959	95.3	35.0	36.7	23.2	24.3	26.1	27.4	26.1	27.4
1960	95.3	34.3	36.0	24.4	25.6	26.0	27.3	26.2	27.5
1961	94.8	35.2	37.1	26.3	27.7	25.9	27.3	26.7	28.2
1962	94.8	34.5	36.4	26.3	27.7	25.6	27.0	26.4	27.8
1963	94.7	33.5	35.4	25.4	26.8	25.0	26.4	25.7	27.1
1965	95.2	32.9	34.6	25.3	26.6	24.5	25.7	25.3	26.6
1965	96.4	33.3	34.5	24.9	25.8	24.4	25.3	25.3	26.1
1966	98.5	32.9	33.4	25.0	25.4	24.6	25.0	25.4	25.8
1967	100.0	33.0	33.0	24.6	24.6	25.2	25.2	25.8	25.8
1968	102.5	34.1	33.3	25.1	24.5	25.0	25.0	26.3	25.7
1969	106.0	33.9	32.0	25.6	24.2	25.2	25.2	27.2	25.7
1970	110.0	39.8	36.2	27.2	24.7	28.4	28.4	31.3	28.5
1971	114.0	55.5	48.7	29.1	25.5	31.8	31.8	40.0	35.0
1972	117.9	62.1	52.7	31.1	26.4	32.6	32.6	41.1	35.5

1/ Industrial commodities Wholesale Price Index, 1967=100.

Source: Current data from Edison Electric Institute.

Table 4

ESTIMATED EMISSIONS OF AIR POLLUTANTS BY WEIGHT,
NATIONWIDE, 1970
(Preliminary Data)

(In millions of tons per year)

Source	CO	Particulates	SO_x	HC	NO_x	Totals
Transportation	110.0	0.7	1.0	19.5	11.7	142.9
Fuel Combustion in stationary sources	.8	6.8	26.5	.6	10.0	44.7
Industrial processes	11.4	13.1	6.0	5.5	.2	36.2
Solid waste disposal	7.2	1.4	.1	2.0	.4	11.1
Miscellaneous	16.8	3.4	.3	7.1	.4	28.0
Total	147.2	25.4	33.9	34.7	22.7	263.9
Percent change 1969-1970	-4.5	-7.4	0	0	+4.5	

Source: Environmental Protection Agency.

TABLE 5.

TYPICAL ANALYSIS OF STACK GASES FROM COAL-FIRED BOILERS

COMPONENT		TYPE OF BOILER					
		Vertical	Corner	Front-Wall	Spreader-Stoker	Cyclone	Horizontally Opposed
H_2O (v)	(%)	5.7	8.1	6.3	7.5	5.9	6.5
CO_2	(%)	12.2	14.3	13.0	11.8	12.7	13.0
O_2	(%)	6.4	4.8	5.6	7.0	6.3	6.1
NO_x	(ppm)	310	413	606	437	1160	350
SO_2	(ppm)	1730	1130	1680	1570	1360	1380
SO_3	(ppm)	9	12	7	76	31	9
CO	(ppm)	11	16	6	32	--	51
Hydrocarbons	(ppm)	14	8	6	8	0	0
Formaldehyde	(ppm)	0.25	0.17	0.14	0.06	0.17	0.10

NOTE:

(1) All measurements made After Fly-Ash Collector, except for formaldehyde which were made Before Fly-Ash Collector.

TABLE 6.

PLANNED AND OPERATING FULL SIZE FLUE GAS DESULFURIZATION FACILITIES IN THE UNITED STATES

	Utility Company/Plant/New or Retro	Megawatts	Startup	Fuel
	LIMESTONE SCRUBBING			
1.	Union Electric Co. (St.Louis)/ Meramec No. 2/Retro		Abandoned	3.0% S Coal
2.	Kansas Power & Light/Lawrence Station No. 4/Retro	125	December 1968	3.5% S Coal
3.	Kansas Power & Light/Lawrence Station No. 5 New in 1971	430	November 1971	3.5% S Coal
4.	Commonwealth Edison (Chicago Area)/ Will County Station No. 1/Retro	175	February 1972	3.5% S Coal
5.	City of Key West/Stock Island/New	37	March 1973	2.75% S Fuel Oil
6.	Kansas City Power & Light/Hawthorne Station No. 3/Retro	130	November 1972	3.5% S Coal
7.	Kansas City Power & Light/Hawthorne Station No. 4/Retro	130	August 1972	3.5% S Coal
8.	Louisville Gas & Electric Co./ Paddy's Run Station No.6/Retro	70	February 1973	3.5% S Coal
9.	Kansas City Power & Light/La Cygne Station/New	820	March 1973	5% S Coal
10.	Detroit Edison Co./St. Clair Station No.8/Retro	180	December 1973	3.7%-3.8% S Coal
11.	Arizona Public Service Co./Cholla Station/Retro	115	April 1973	0.4%-1% S Coal
12.	Union Electric Company (St. Louis)/ Meramec No. 1/Retro	140	Spring 1973	3.0% S Coal
13.	Duquesne Light Co. (Pittsburgh)/ Philips Station/Retro	100	Spring 1973	2% S Coal
14.	Tennessee Valley Authority/Widow's Creek Station No. 8/Retro	550	April 1975	3.7% S Coal
15.	Northern States Power Co. (Minnesota) Sherburne Co. Station No. 1 & 2/New	1360 2-680	May 1976 First Unit	0.8%-1.2% S Coal
16.	Southern California Edison & Other Southwestern Utilities/Navajo/New	2250 3-750	1-Unit/Mar. 1976 3-Unit/Mar. 1977	0.3-0.8% S Coal
	SODIUM-BASE SCRUBBING			
17.	Nevada Power Co./Reid Gardner Station/Retro	250	Mid 1973	0.5%-1.0% S Coal
18.	Northern Indiana Public Service Co./ D.H. Mitchell No. 11 (Wellman-Lord Process)/Retro	115	July 1974	3.5% S Coal
	MAGNESIUM OXIDE SCRUBBING			
19.	Boston Edison/Mystic Station No. 6/Retro	150	April 1972	2.5% S Fuel Oil
20.	Philadelphia Electric Co./Eddystone 1/ Retro	120	Mid 1973	2.5% S Coal
21.	Potomac Electric & Power (Maryland) Dickerson No. 3/Retro	100	Early 1974	3.0% S Coal
	[illegible]			
22.	Illinois Power/Wood River/Retro	100	Sept.	3.25% S Coal

TABLE 7.

Estimated Capital and Operating Costs for Some SO_2 Control Processes(26) on a Kilowatt Basis

Process	Capital Cost $/Installed kw 1/	Operating Cost 2/ mills/kwhr	SO_2 Removal Efficiency	Particulate Removal Included	Comments
Wet Limestone	27-46	0.7-1.5	80-90%	Yes	Costs dependent on solids removal consideration, new or retrofit, scrubber type cost of lime or limestone, size of unit, type of coal, etc.
MgO	33-58	0.4-1.0	90%	Yes	Cost dependent on factors similar to wet limestone.
Monsanto Catalytic Oxidation	41-64	0.5-1.0	85-90%	Yes	Cost dependent on factors similar to wet limestone.
Wellman-Lord	38-65	.6-1.3	90%	Yes	Cost dependent on factors similar to wet limestone.

1/ Lower cost refers to a new large size unit (1,000 Mw) while the higher cost refers to a small (200Mw) retrofit unit.

2/ 75% load factor, 18% capital charges assumed.

Table 8. United States Uranium Resource
January 1, 1973
(Tons U_3O_8 in Ore)

Cost Cutoff $1/lb. U_3O_8	Production 1948-1972	Reserves 1/	Potential 2/	Production Plus Resource
$8	244,000	273,000	450,000	967,000
$15	-	520,000 3/	1,000,000	1,764,000

1/ Reserves represent uranium in known deposits for which detailed information is available, usually from surface drilling. The estimates include all ore producible at less than a stated cost of production which includes all future expenditures required to develop, mine, transport and process the ore to recover the uranium.

2/ Potential resources refer to additional uranium that may exist in known favorable geologic environments, primarily in or around the areas containing ore reserves. Because geologic knowledge of the United States is incomplete and the estimates have been largely confined to producing areas, they do not represent a complete appraisal of U.S. resources.

Table 9 . Hydroelectric Power Resources of the United States by Geographic Divisions

Area 1/	Developed 2/		Undeveloped		Total Potential 3/		Percent Total potential capacity now developed	Percent Total potential generation now developed
	Capacity (MW)	Average annual generation (million Kwhrs)	Capacity (MW)	Average annual generation (million Kwhrs)	Capacity (MW)	Average annual generation (million Kwhrs)		
New England	1,480	5,087	3,349	8,325	4,829	13,412	30.6	37.9
Middle Atlantic	5,967	28,851	2,625	9,038	8,592	37,889	69.4	76.1
East North Central	839	4,279	1,410	5,455	2,249	9,734	37.3	43.[illegible]
West North Central	3,089	14,325	3,966	14,002	7,055	28,327	43.7	50.5
South Atlantic	5,505	17,480	8,957	16,785	14,462	34,265	38.0	51.0
East South Central	5,259	25,160	3,843	3,287	9,102	28,447	57.7	88.4
West South Central	2,279	3,921	2,846	7,286	3,125	11,207	44.4	34.9
Mountain	6,601	39,276	25,792	80,670	32,393	119,946	20.3	24.4
Pacific Contiguous	25,467	143,987	36,274	101,238	62,191	245,225	40.9	58.7
Pacific Non-contiguous	80	368	32,529	172,687	32,609	173,055	.2	.2
Total U.S.	56,566	272,734	122,041	428,773	178,607	701,507	31.6	38.8

1/ New England Area includes Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut. Middle Atlantic Area includes New York, New Jersey, Pennsylvania. East North Central Area includes Ohio, Indiana, Illinois, Michigan, Wisconsin. West North Central Area includes Minnesota, Iowa, Missouri, N. Dakota, S. Dakota, Nebraska, Kansas. South Atlantic Area includes Delaware, Maryland, Washington, D. C., Virginia, West Virginia, N. Carolina, S. Carolina, Georgia, Florida. East South Central Area includes Kentucky,Tennessee, Alabama, Mississippi. West South Central Area includes Arkansas, Louisiana, Oklahoma, Texas. Mountain Area includes Montana, Idaho, Wyoming, Colorado, New Mexico, Arizona, Utah, Nevada. Pacific Contiguous Area includes Washington, Oregon, California. Pacific Non-contiguous Area includes Alaska, Hawaii.

2/ Federal Power Commission News Release No. 19370, June 27, 1973. Data to December 31, 1972.

3/ Federal Power Commission, Hydroelectric Power Resources of United States, Developed and Undeveloped, January 1, 1972.

Table 10. United States Hydropower Capacity and Generation, 1972 Actual, with Projections to 2000 (Base Scenario)

Year	Total Hydro capacity (MW)	Total Generation (million Kwhrs)
1972	56,566	272,734
1975	60,000	284,700
1980	68,000	312,600
1985	74,000	339,000
1990	82,000	361,900
2000	91,000	393,600

Table 11. Cumulative Costs of Hydropower Construction, 1972-2000

Period	Increase in capacity over 1972	Cumulative Cost (billions) *
1972-75	3,434	1.03
-80	11,434	3.43
-85	17,434	5.23
-90	25,434	7.63
-2000	34,434	10.33

* Based on an average cost of $300/KW installed capacity.

Table 12. Hydroelectric Power Resources of the Northern Great Plains Region

State	Developed		Undeveloped		Total Potential		Percent total	
	Capacity (MW)	Average annual generation (million Kwhrs)	Capacity (MW)	Average annual generation (million Kwhrs)	Capacity (MW)	Average annual generation (million Kwhrs)	Capacity now developed	Percent total potential generation now developed
North Dakota	400	1,886	195	840	595	2,726	67.2	69.2
South Dakota	1,392	4,437	303	883	1,695	5,320	82.1	83.4
Montana	1,512	8,208	6,136	21,760	7,648	29,968	19.8	27.4
Wyoming	222	989	1,273	6,103	1,495	7,092	14.8	13.9
Nebraska	238	1,183	1,018	3,388	1,257	4,571	18.9	25.9
Total	3,764	16,703	8,926	32,974	12,690	49,677	22.5	33.6

Source: Federal Power Commission, "Hydroelectric Resources of the United States, Developed and Undeveloped", January 1, 1972

Table 13 . Fuel, Water, Capital, and Personnel Requirements for a 1,000 MW Coal-Fired Powerplant

Plant type	Year of initial operation	Cooling	Annual water requirements (acre ft.)	Annual coal requirements (million tons)[1]	Coal reserves 30-yr. life (million tons)	Heat rejection to water (Btu/yr)	Heat rejection to air (Btu/yr)	Heat rate Btu/kwhr	Thermal efficiency (%)	Capital investment (1972) [2] ($ million)	Personnel requirements (operation only)
Conventional Steam	1970-1980	Once through water	565,000 (20° rise)	3.46	103.9	3.12×10^{13}	6.2×10^{12}	8,530	40	225	125
Conventional Steam	1972-1980	Cooling Tower	11,500 Evaporated	3.46	103.9	Negligible	3.74×10^{13}	8,530	40	225	125
Conventional Steam	1972-1980	Dry Air	Negative	3.97	119.1	Negligible	4.64×10^{13}	9,750	35	225	125
Coal-gas-gas turbine-steam	1980-1990	Cooling Tower	7,360 Evaporated	2.82	84.6	Negligible	2.54×10^{13}	6,820	50	250	150
Coal-gas-gas turbine-steam	1980-1990	Dry Air	Negative	3.13	93.9	Negligible	3.10×10^{13}	7,580	45	250	150

[1] Based on 9,000 Btu/lb. subbituminous coal

[2] Capital investment data valid only for western States in 1972.

APPENDIX VI-B.

STACK GAS CLEANUP PROCESSES

Stack Gas Cleanup Processes

Wet Lime/Limestone Process.

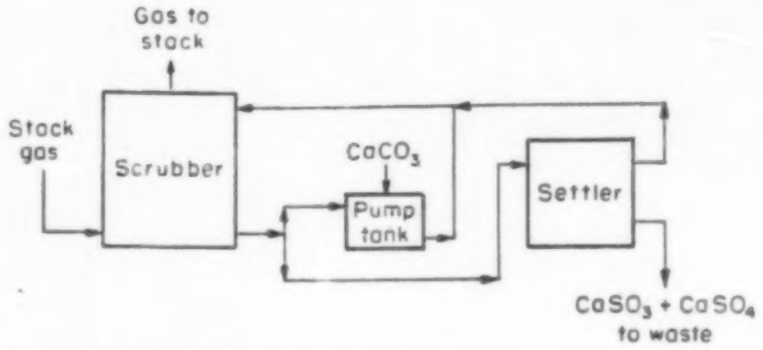
The importance of lime/limestone scrubbing is immediately evident from Appendix A-9 which shows that 16 of the 22 processes are this type. In the wet lime/limestone process, which is the most thoroughly studied of all of the control systems, lime and/or limestone is reacted with SO_2 to form sulfates and sulfites which are then collected and discarded. Therefore, lime/limestone systems are "throwaway" systems. Another system, dry injection of limestone directly into the boiler, was studied prior to development of the wet process but, although dry injection is a simple economical control technique, removal efficiency is only 30 to 50 percent, possibly suitable in some cases, but not high enough for widespread application. A wet scrubbing step was, therefore, introduced to increase removal efficiency.

The wet process has three variations as shown in Figure 7.(29) In method one, limestone ($CaCO_3$) is injected into the wet scrubber where it contacts the flue gas and forms sulfites and sulfates. This is the simplest of the three methods, but limestone is not as reactive as lime (CaO) and it is necessary to install a larger scrubber, recirculate more slurry and grind the limestone finer to make up for the lower reactivity.

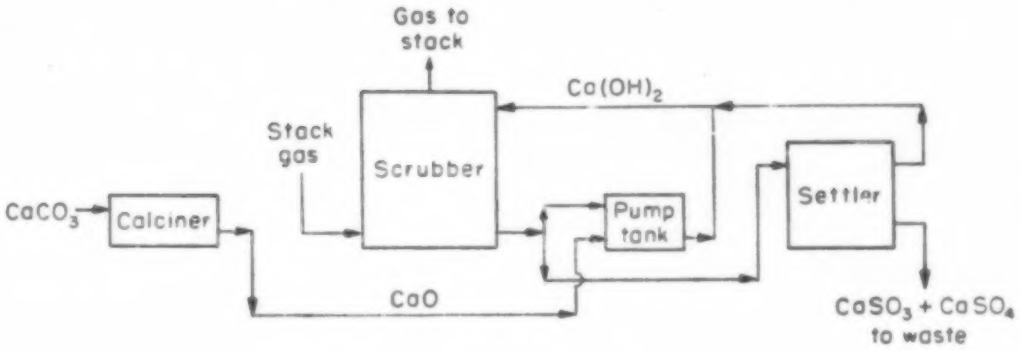
In method two, the limestone is calcined to lime, which is slaked and then introduced into the scrubber as calcium hydroxide ($Ca\,(OH)_2$). Although lime is more reactive than limestone, a lime kiln installation is required for calcination. This adds a considerable expense to the process. Also, the use of lime increases the problem of deposit formation in the scrubber.

FIGURE 1.

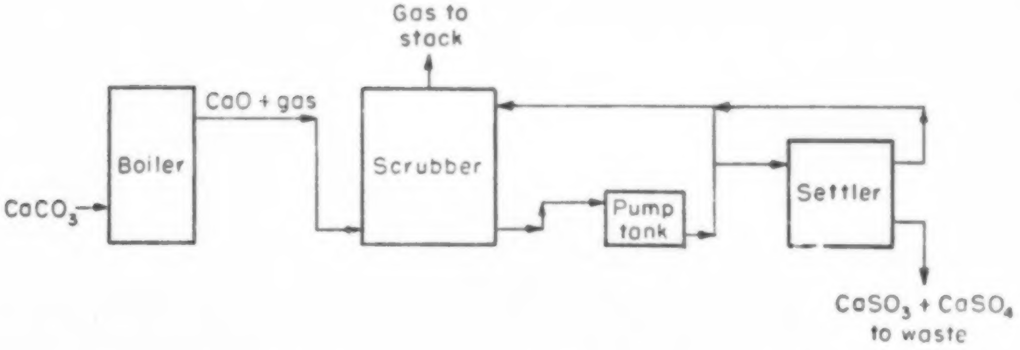
Lime/Limestone Processes
for Removing SO_2 from Stack Gases


Gas to stack
Stack gas
Scrubber
$CaCO_3$
Pump tank
Settler
$CaSO_3 + CaSO_4$ to waste

Method 1 - Scrubber addition of limestone


Gas to stack
$Ca(OH)_2$
Stack gas
Scrubber
$CaCO_3$
Calciner
Pump tank
Settler
CaO
$CaSO_3 + CaSO_4$ to waste

Method 2 - Scrubber addition of lime


Gas to stack
Boiler
CaO + gas
Scrubber
$CaCO_3$
Pump tank
Settler
$CaSO_3 + CaSO_4$ to waste

Method 3 - Boiler injection followed by wet scrubbing

L-13015

A third variation of the wet-limestone process involves dry injection of limestone into the boiler after which the partially reacted material is carried to a wet scrubber. Further reaction of the limestone and the SO_2 occurs in the wet scrubber results in additional removal. Problems, which have been encountered in this variation, are boiler fouling, over-burning and inactivity of the lime, and plugging and scaling in the scrubber.

All three variations of wet limestone simultaneously remove particulates in the wet scrubber. Most of the present systems also utilize a closed loop for the scrubbing liquid whereby the liquid is recirculated and a solid waste product is then obtained for disposal. This is done to eliminate the possiblity of water pollution.

As mentioned earlier, the testing of the limestone processes is more comprehensive than any others. Method three has been studied by Combustion Engineering on a pilot plant level at a Detroit Edison powerplant where 98 percent SO_x removal was obtained with a tray-type absorber. Combustion Engineering, Inc. has made large scale installations at the Meramec Station of Union Electric Co. (140 MW, existing), the Kansas Power and Light Co. in Lawrence, Kansas (125 MW, existing) and Kansas Power and Light, Lawrence Station (420 MW, new). Good removal efficiency has been consistent, but plugging and scaling problems have been significant. The Meramec plant's wet-limestone system had to be shut down because of problems of this type. Combustion Engineering is piloting method No. 1 on a 700 MW scale at the Sherbourne

(Minnesota) powerplant, and Babcock and Wilcox is piloting a similar system at the 175 MW Will County plant.

The Tennessee Valley Authority has been extensively involved in research on limestone processes for a number of years. A limestone slurry scrubbing system is presently being constructed at a 500 MW unit on the Widows Creek TVA plant in Alabama, and an extensive prototype testing program is being initiated at TVA's Shawnee Powerplant in Kentucky. The Shawnee project, sponsored by EPA, involves a test facility designed by Bechtel, Inc., which will encompass several limestone operating modes, including injection of limestone into the boiler and directly into the scrubber. Testing will include the use of turbulent venturi and flooded marble bed scrubbers.

Wet lime/limestone scrubbing processes have the advantages of low capital and operating costs and high removal efficiencies. They suffer, however, from the disadvantage of scaling and plugging problems and solid waste disposal.

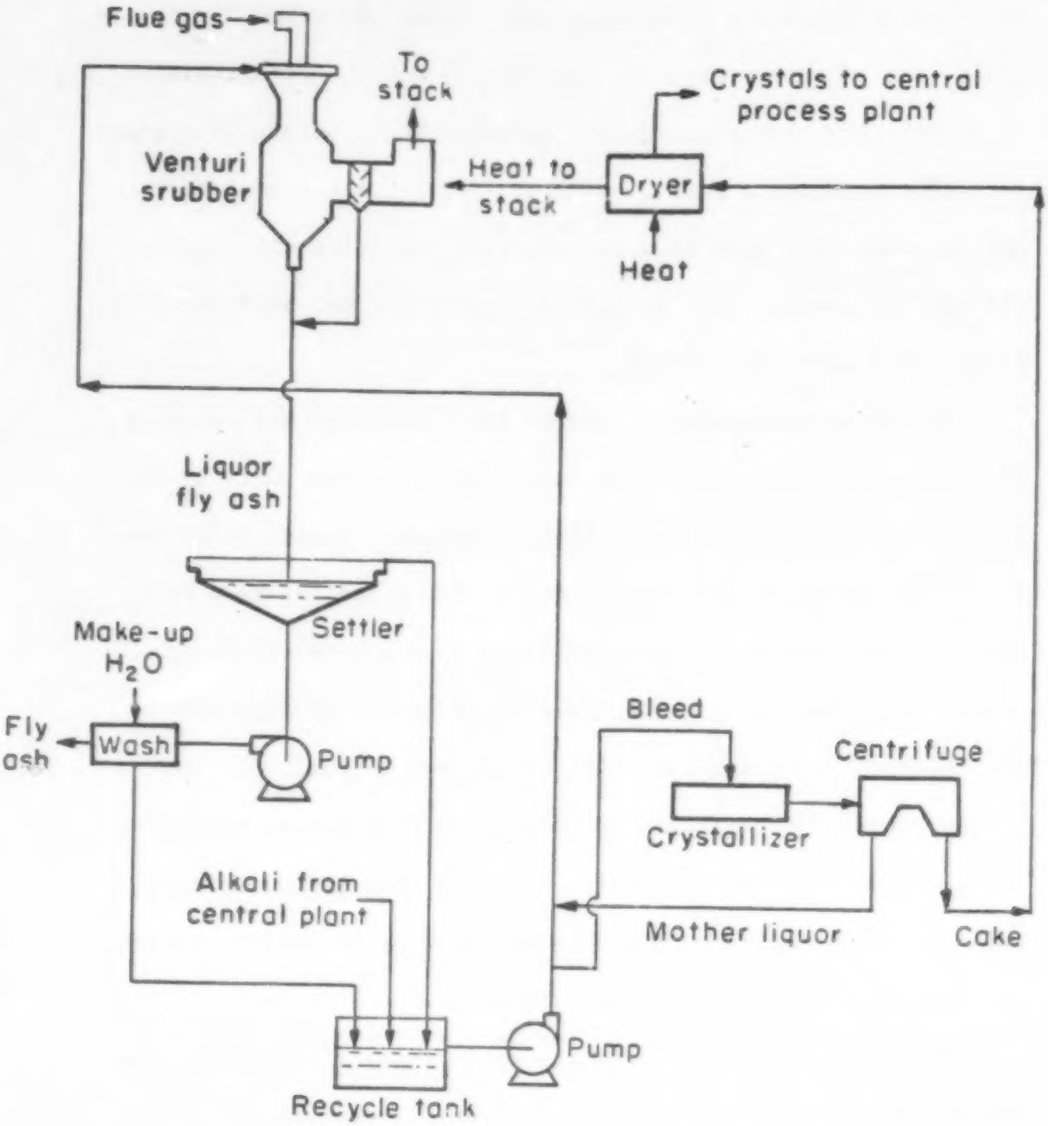
Magnesium-Oxide Scrubbing Prosess.

The magnesium-oxide (MgO) scrubbing process is similar in many ways to the wet limestone process.(14) The major difference is that sulfite and sulfate salts, formed after reacting an MgO slurry with SO_2, are regenerated at a separate chemical processing plant. The regeneration produces a concentrated stream of 15 percent SO_2 and fresh MgO for reuse in the scrubber loop.

As shown in Figure 8 flue gas enters the venturi scrubber where it contacts an MgO slurry which removes SO_2. The flue gas then passes through a separator demister section and exhausts to

FIGURE 2.

Magnesium Oxide Process for Removing SO_2 From Stack Gases


Flue gas
To stack
Crystals to central process plant
Venturi srubber
Heat to stack
Dryer
Heat
Liquor fly ash
Settler
Make-up H_2O
Fly ash
Wash
Pump
Bleed
Centrifuge
Crystallizer
Alkali from central plant
Mother liquor
Cake
Pump
Recycle tank

L-13014

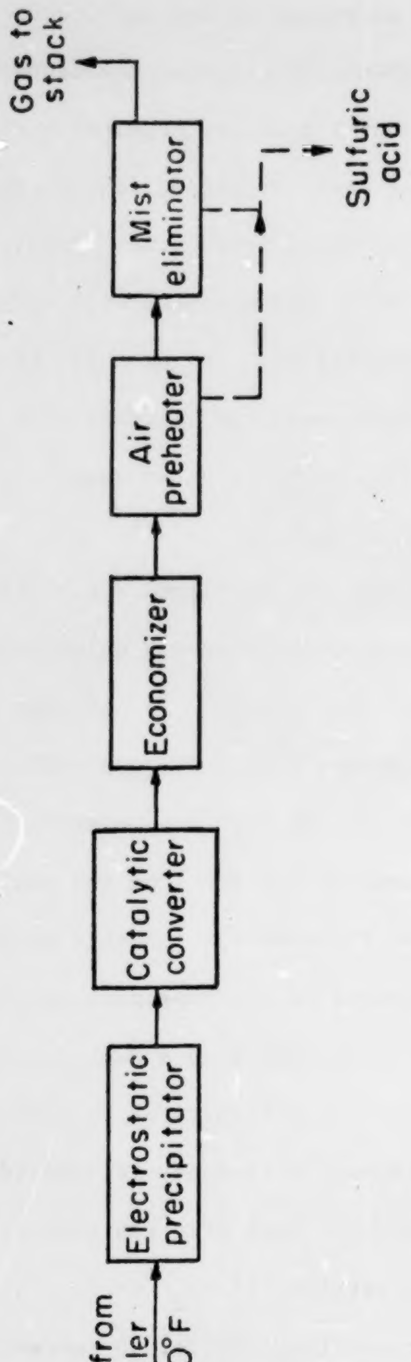
the stack. The spent reactant liquid is processed to separate fly ash and the remaining effluent, containing magnesium sulfate and sulfite salts, is thickened, centrifuged and dried for transport. The anhydrous crystals leaving the drier, after addition of carbon, are next reacted in a direct-fired calciner to regenerate MgO and release sulfur oxides. Finally, the regenerated MgO is mixed with make up water and recycled while the calciner off-gas (15 percent SO_2) is sent to a conventional sulfuric acid plant for further processing.

Developed originally by the Grillo Company of West Germany, the magnesium-oxide process is being funded in the U. S. by EPA in conjection with the Boston Edison Company. Design is by the Chemico Corporation and the process is being applied on a test basis to the combustion gases produced in a 150 MW oil-fired boiler installation at Boston Edison's Everett, Massachusetts powerplant. Spent reactant will be shipped to Rumford, Rhode Island, where MgO regeneration will be carried out at the Essex Chemical Company plant. Product SO_2 will then be converted to sulfuric acid, while the MgO will be returned to Boston Edison for reuse in further stack gas scrubbing.

Recently the Potomac Electric Power Company announced plans for installation of a Chemico basic type SO_2 removal and recovery system at its Dickerson coal-fired power station. The Dickerson prototype plant is scheduled for operation in 1973. Once again, spent reactant (magnesium sulfite) will be shipped to Rumford, Rhode Island, for SO_2 regeneration, followed by conversion to sulfuric acid or elemental sulfur.

FIGURE 3.

Cat-Ox Process for Removing SO_2 from Stack Gases


Gas from boiler
850°F
Electrostatic precipitator
Catalytic converter
Economizer
Air preheater
Mist eliminator
Gas to stack
Sulfuric acid

L-13013

The significant advantage of the MgO process is the regeneration system which, eliminating the disposal problem common to many SO_2 control systems, produces a saleable byproduct. On the other hand, utilities do not, in general, wish to get involved with chemical processing. Also, the value of the concentrated sulfuric acid produced will vary considerably depending on market conditions. Conceivably, if a large number of plants used such a process, the sulfuric acid byproduct could become a liability rather than an asset.

Catalytic Oxidation Process.

The Monsanto Company has developed a variation of the contact sulfuric acid process for removing dilute concentrations of sulfur dioxide from flue gases.(18) Although two versions of the Monsanto process are proposed - one applicable to existing plants, the other for use with new powerplants - both require thorough removal of fly ash from the combustion gases prior to SO_2 oxidation and removal. In this process (Figure 9), which is the most advanced of the byproduct recovery processes, flue gas passes from the boiler into a combination mechanical collector and electrostatic precipitator to effect 99.5 percent removal. This high removal efficiency is very important to prevent fouling the catalyst. Dust free gas then enters the catalytic unit for conversion of SO_2 to SO_3 at about 850°F. By maintaining the proper temperature, 90 percent plus removal efficiency can be obtained. The SO_3 and steam in the flue gas then react to form sulfuric acid, which is removed in an absorption tower. The product material is about 80 percent sulfuric acid.

The add-on version for existing powerplants is being scaled-up for installation on a 100 MW unit at the Illinois Power Company's Wood River (Illinois) Powerplant. The critical process problems, which will be examined on this scale, are fly ash removal, life expectancy of the catalyst and the frequency with which the catalyst must be cleaned. The cost of the catalytic oxidation demonstration, which will be shared by EPA and the Illinois Power Company, is $5.7 million. The unit has started up and testing is underway.

The Cat-Ox process, as it is called, is relatively simple and has an economic advantage in that no raw material other than flue gas and catalyst are required. Furthermore, no disposal problems are encountered. On the other hand, the sulfuric acid produced is of marginal value because it is dilute (about 70 percent). Other disadvantages are that a large amount of installation space is required and estimated capital costs have been relatively high, ranging between $35 and $45 per installed kilowatt. The Illinois Power Company demonstration plant is reported to have cost $66 per kw.

Other Processes Under Development.

Wellman-Lord - This process utilizes a sodium sulfite-bisulfite scrubbing solution which is subsequently steam stripped to remove SO_2 and evaporated to produce crystals of sodium sulfite.(25) The SO_2 stream can be treated to produce sulfur or sulfuric acid. Some oxidation of sulfite to sulfate occurs in the absorber and this necessitates a caustic makeup and a purge stream. The process has operated on both a sulfuric acid plant in the U. S. and an oil-fired powerplant in Japan. The 70 MW scale powerplant operation was reported to be very successful with 90 percent removal obtained when burning a four percent sulfur fuel oil. Because of the results in Japan, this process is thought to have significant promise. A demonstration plant will be constructed on a Northern Indiana Public Service Company 115 MW coal-fired powerplant. Jointly funded by the utility and EPA, startup is scheduled for July 1974.

Dry Sorption Processes - The Bureau of Mines, Esso Research and Engineering, and Shell Oil Company each have described a process for sorption of SO_x on a dry sorbent, e.g. copper oxide on alumina.(12,20) Sorption occurs at 650°F. Following saturation, the sulfur dioxide is released by passing reducing gas through the bed at a temperature the same as, or a little higher than, that at which sorption occurred. Dry processes such as these have the advantages of low cost and applicability to existing plants. Esso, in association with Babcock-Wilcox, is scheduled to test their process on a 150 MW coal-fired boiler on the American-Electric Power System's Lawrenceburg, Indiana plant.

Bureau of Mines Citric Acid Process One of the few organic liquid sorbent processes, this system was initially developed to remove SO_2 from smelter gas.(27) In this process, a solution of buffered citric acid is used to absorb SO_2. The spent solution is regenerated by the addition of H_2S which reacts with the absorbed SO_2 to produce elemental sulfur. The sulfur then is separated and the solution is then recycled.

The system is said to be capable of removing over ninety percent of the SO_2 from stack gases and will be tested on a large scale in a joint project involving Peabody Engineering, A. G. McKee Co., and Pfizer Chemical Company. Peabody will fabricate and assemble a mobile self-contained 2,000 cfm unit to McKee's design specifications. Pfizer will provide the citric acid and the chemical expertise for the demonstration unit which will be installed at its Vigo plant in Terre Haute, Indiana. Operating and test data are expected to become available in the first quarter of 1973. Preliminary cost information indicates a capital investment of $30 per kw and an operating cost of 1.5 mills per kw hr., based on a 1,000 MW plant burning three percent coal. Pilot plant scaleup is in the construction stage.

Consolidation Coal Company Potassium Formate Process - At 200°F SO_2 reacts with potassium formate (KOOCH) solution to produce $K_2S_2O_3$. This, in turn, is reacted at 540°F with additional KOOCH to make K_2CO_3 and potassium hydrosulfide. (35) The latter is converted to H_2S and then to elemental sulfur. Treatment with CO at 1,000 psi and 540°F converts K_2CO_3 back to KOOCH. Bench-scale performance of all steps of the process has been achieved, and pilot plant work is underway in anticipation of private industry development of the process.

Universal Oil Products (UOP) Process - This wet scrubber system uses a contact absorber which absorbs particulates while using an alkaline slurry to remove SO_2.(14) After regeneration from the sorption solution, the sulfur dioxide is reacted with H_2S and thus converted to elemental sulfur. Residual SO_2 in solution is contacted with reducing gas to form H_2S and the regenerated sorbent solution recirculated to the scrubber for reuse. A $4 million pilot plant to treat 80,000 cu. ft. of stack gas per minute started initial operation in December 1972. This project is being built for the Commonwealth Edison Co. at its State Line generating station at Hammond, Indiana.

Atomic International's Molten Carbonate Process - In this process flue gas is contacted with an eutectic mixture of molten lithium, potassium, and sodium carbonates to form sulfites and sulfates dissolved in the unreacted carbonates.(7) Reaction with carbon monoxide and hydrogen reduces the sulfates and sulfites to sulfides. Steam and carbon monoxide are then used to regenerate the original mixture for reuse. A pilot plant is to be constructed at the 335 MW Consolidated Edison's Arthur Kill Station on Staten Island. Plant startup is scheduled for March 1973.

Stone and Webster/Ionics - In this process, SO_2 is absorbed by reaction with NaOH in a wet scrubber to form sulfite and bisulfite.(14) The unique aspect of this process lies in a patented electrolytic membrane diaphragm cell that regenerates the NaOH. Dry SO_2, which could be fed to an acid plant, is recovered. The process was piloted at Tampa Electric Company's Gannon plant and a full scale demonstration on a 70 MW boiler is planned at the Wisconsin Electric Power Company's Valley plant in Milwaukee.

The following are other processes which are receiving attention but are not as developed as the ones just described:

a. Manganese dioxide (Mitsubushi) - Sulfur dioxide is oxidized to metal sulfate followed by regeneration of ammonium sulfate.

b. Ammonia scrubbing (Bureau of Mines, TVA, Nippon Kokan, IFP) - Sulfur dioxide is absorbed and concentrated in ammonia solution. Bureau process utilizes ammonia injection for absorption.

c. Activated Carbon (Reinluft, Westvaco, Hitachi, and Chemiebau) - All methods depend on absorptive powers of various forms of active carbon to first concentrate and then catalyze oxidation of SO_2 to SO_3 for acid of sulfate production.

d. CALSOX - An organic liquid sorbent system being developed by Monsanto Company, the CALSOX Process involves wet absorption followed by regeneration through the addition of lime. There are plans for a prototype installation at an Indianapolis Power and Light Company powerplant. A similar process, NOSOX, is being developed by Monsanto. NOSOX, still at the bench scale, utilizes absorption in an aqueous organic sorbent which, subsequently is steam stripped to remove SO_2.

e. Fluid Bed Combustion - Esso Research and Engineering Company is studying the feasibility of burning coal under high pressure in a fluid bed of limestone. $CaSO_4$ is formed and regenerated by a reducing gas in second reactor.

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APPENDIX VI-C.

ADVANCED POWER CYCLES

ADVANCED POWER CYCLES

The conventional steam cycle power system has been improving in overall efficiency from 1949 through 1965, whereupon it became relatively stable. This trend is indicated in fig. 1, 1/ a graph of heat rates over the last decade. The heat rate of a power plant is the amount of heat required to produce a given quantity of electricity and is therefore the inverse of efficiency. The theoretical efficiency of the steam cycle improves as the temperature and pressure of the steam (currently at 1000°F and 3500 Psi). Equipment manufacturers and architect-engineering firms who were questioned agree that these parameters are not likely to be improved in the next 10-20- years.2/ The increased costs of available but expensive new materials would not be economically justified. In addition, the industry has and will have the task of meeting current air quality standards. Existing pollutiant removal systems such as scrubbers and precipitators will further reduce the limited efficiencies. Fig. 1 or above.

There are, however, possible alternative systems for converting fossil fuels to electricity which show increasing promise. Various government agencies and industrial firms have been doing work on a number of arrangements of advanced power cycles. Some of the more common arrangements are depicted in Fig. 2 below. While the processing of fuels such as coal gasification is often considered to be an integral part of an advanced power cycle, this paper will emphasize the electrical generation systems which could replace or augment the conventional steam-turbine cycle. It will be shown that many of the difficulties of current systems can be overcome with advanced cycles while maintaining economic compatability.

As indicated in fig. 2, the alternatives to direct boiler firing with coal include a number of arrangements of the technologies of magnetohydrodynamics (MHD) and the Gas turbine. These might be used individually or as a topping cycle in conjuction with a conventional steam turbine cycle. A topping cycle is one which extracts the high temperature energy of combustion and passes on the lowered temperature exhaust for use in a base cycle. Fuel for these cycles will be oil, natural and synthetic gas for the turbine, and coal and oil for MHD. These technologies are discussed individually and as incorporated with the steam cycle in the following paragraphs.

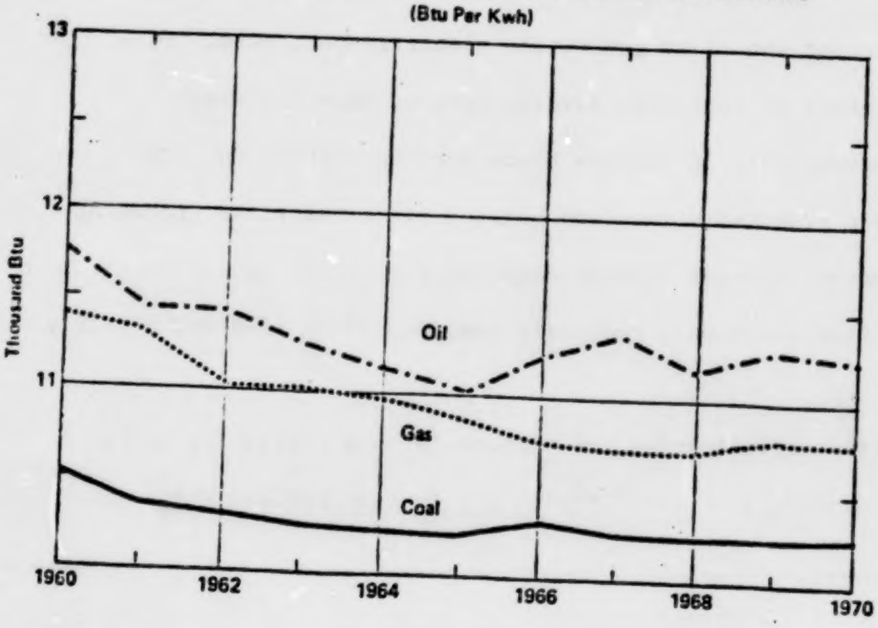
Gas turbine- Present use of gas turbines in powerplants is in most cases confined to peaking applications. A recent study 3/ has indicated that second and third generation gas turbine base load plant busbar costs per Kwh will be competitive with coal fired steam plant costs. This is the cost at the point of consumption and therefore includes transmission costs and profits. The cost of sulfur removal equipment needed in the coal fired plants, when accounted for, would make even existing gas turbine technology competitive. Thermal efficiencies for first, second and third generation plants range from 27-40 + %, which is comparable to current conventional base-load steam plants.

In gas turbine technology, the two major parameters affecting efficiency are turbine inlet temperature and compresor pressure ratio. A currently attainable temperature of 2000°F is expected to be increased to 2800°F

Figure 1

U.S. STEAM - ELECTRIC UTILITY HEAT RATE EXPERIENCE, 1960–1970

(Btu Per Kwh)



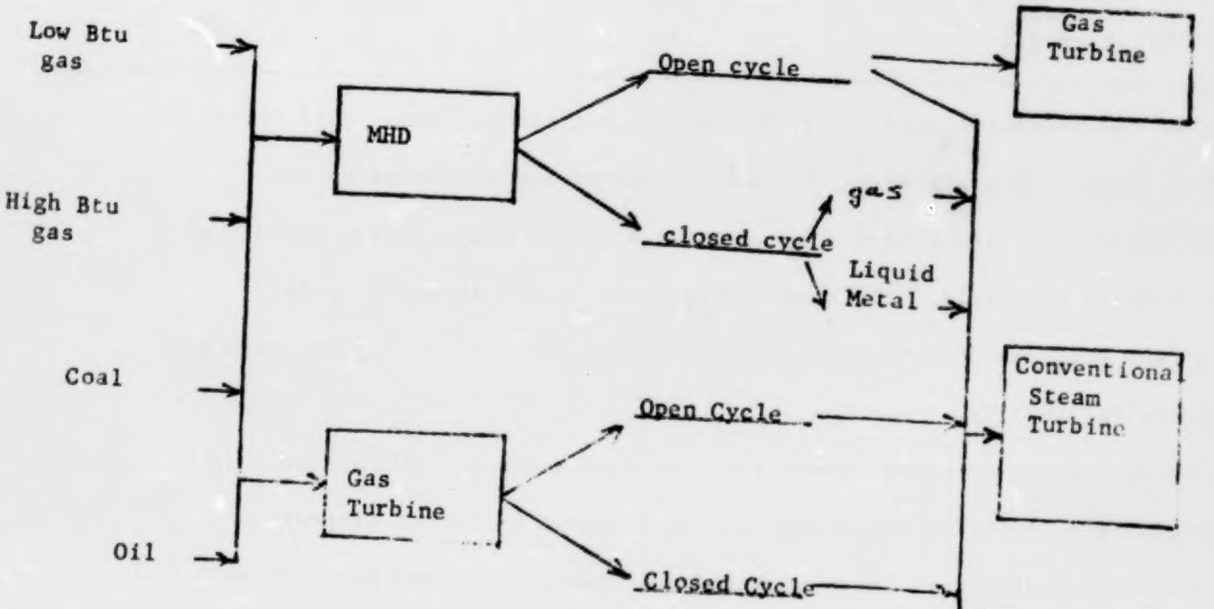

Low Btu gas
High Btu gas
Coal
Oil
MHD
Open cycle
closed cycle
gas
Liquid Metal
Gas Turbine
Open Cycle
Closed Cycle
Gas Turbine
Conventional Steam Turbine

Fig. 2 Advanced Power Cycle

and 3100°F for second and third generation plants respectively. This will be brought about by continued developments of heat resistant materials and improvements in turbine blade cooling techniques. The greatest gains are expected with blade cooling since materials upgrading would be very costly. Current turbine compressor pressure ratios of 15 are expected to rise to 28 with two-shaft compressors by 1976 and possibly to 40 by 1990.

Table 1. gives efficiencies for various turbine cycles for three generations of technology.

Table 1. - Turbine Efficiencies

	Present	1980 (Uncooled Bleed Air)	1980 (Cooled bleed air)	1990
Simple Cycle				
Inlet Temp. °F	1,700	2,400	2,400	3,000
Efficiency, %	27	31	38	41
Regenerative Cycle				
Inlet temp. °F	2,000	2,000	2,400	3,000
Efficiency, %	35	37	41	45
Compound Cycle				
Inlet temp. °F		2,000	2,400	
Efficiency,%		30	42	

All of the systems listed in table 1 are open cycle systems. This refers to the working fluid, air, being compressed, heated and exhausted to the atmosphere in a single pass. By contrast a closed cycle system would cool and recycle the fluid. The simple, regenerative and compound cycles indicate systems of increasing complexity with associated higher costs and reduced reliability.

For costing purposes, power stations with nominal 1,000 Megawatt (Mw) capacity were selected for comparison in a report by United Aircraft Research Laboratories. These advanced open cycle base-load gas turbine stations were primarily those which could be installed during the next two decades. Calculations for early 1980's design cost were based on a 70% load factor, gas priced at 30¢/MBtu and an 8% interest rate. Station installed capital costs and busbar costs were as follows:

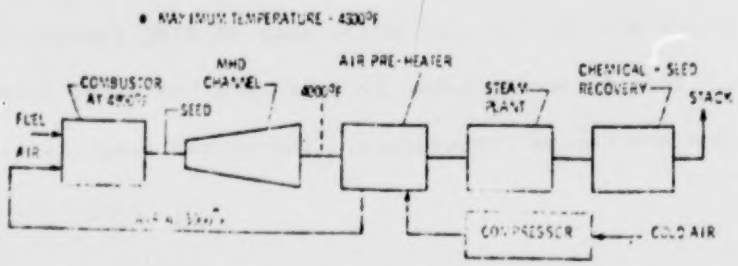
	Capital Costs	Busbar Costs
Steam turbine	$120/Kw	6.01 mills/Kwhr.
Simple cycle gas turbine	$66/Kw	5.19 mills/Kwhr.
Regenerative cycle	$93/Kw	5.79 mills/Kwhr.

Doubling the gas price reduced the difference among the systems but the relative positions in economies is retained.

Closed cycle systems operate on helium which would be best heated in a High temperature Gas Cooled Nuclear Reactor. The expected overall efficiency is about 36%. Costs would be somewhat less than open cycle turbines and the size is considerably less. A 275 Mw plant would compare in size to a 25 Mw open cycle turbine. This system has been demonstrated but is not able as yet to achieve the efficiencies or economies of the open-cycle system.

A second major energy conversion system is Magnetohydrodynamics (MHD). MHD is a system in which power is generated by the flow of a hot ionized gas through a magnetic field. Since the conductor is a fluid, there are no moving parts to wear out. The basic principles of MHD are diagrammed in figure 3.

OPEN CYCLE MHD-STEAM PLANT
(ALTERNATIVE: O_2 REPLACES AIR PREHEAT)


• MAXIMUM TEMPERATURE - 4300°F
COMBUSTOR
MHD CHANNEL
SEED
4000°F
AIR PRE-HEATER
STEAM PLANT
CHEMICAL + SEED RECOVERY
STACK
FUEL
AIR
COMPRESSOR
COLD AIR

There are a variety of configurations of MHD to consider. Among them are: open and closed cycles; one, two and three stage burner designs; linear and cyclone, and those using the various fuels. The most common system is the open cycle single stage combustor configuration. Most foreign programs in MHD Research are based on this type fueled with natural gas. The U.S. effort is strongly emphasizing coal fired generators because of the obvious advantage of fuel availability, however there are some special problems. The Soviets, who are the recognized leaders in MHD research, are making plans to convert their 1.5 Mw Enin II plant to coal. There the construction of a 75 Mw MHD-steam pilot power plant incorporating a 25 Mw MHD generator has just been completed. 4/ Additional pilot plant operations are being conducted in Japan, West Germany, Poland and England, all of which are gas fueled.

Target temperatures of the open cycle coal fired MHD are to exceed 4200°F in order to obtain the desired efficiencies. These efficiencies are generally estimated for the MHD-steam combined cycle which is discussed later, although a singular MHD cycle is feasible and may be desirable for certain applications.

Among the technical areas to be improved are: slagging problems in the duct, heat flux effects in the confining walls, reduction of heat losses, superconducting field magnets and high temperature corrosion and errosion in the air preheater.

Two-stage combustors provide a higher efficiency of slag removal than single stage designs. This is accomplished by operating the first stage at a temperature below the ash fusion temperature. The second stage is to then complete the combustion of the gases produced in the first stage. However there are still problems with incomplete oxidation of coal in the first stage.5/

A three stage combustor consists of a cyclone gasifier, fluid CO_2 reformer and final combustor. This system is a further step in reducing the problems associated with a dirty fuel, ie, coal. However, the approach requires further development in cleaning the gas in which the suspended ash is molten.

Work on these types of generators is continuing at a rapid pace. The AVCO Everatt Research Laboratory has operated units of 32 and 18 MWE for short periods and work is underway for long term operation at power levels up to 500 Kw 6/

The ionization of the gases in the MHD duct is accomplished by "seeding" with potassium or cesium. Cesium seeding results in much higher conductivity of the gases but is also much more expensive. Therefore potassium is more commonly used although either must be recovered from exhaust gases and slag for economical reasons. It has been demonstrated that seed material can be recovered in excess of 99% using a baghouse. 7/ A recent study by the Bureau of Mines 8/ indicates that a mixture of 85 mole-percent Potassium - 15 mole-percent cesium is preferable to either seed material alone. Conductivity is significantly improved, sulfur removal is maintained and the cost is reduced over other systems.

Basic generation and capital costs costs for a 1000 Mw (norminal) power plant without considering sulfur removal as compared by Rosa 9/ are given below:

	MHD			
	Early	Developed	Conv. steam	Nuclear
Capital Cost, $/kw	210	150	225	300
Generation Cost, Mills/Kwhr.	7.05	5.35	7.84	8.67

A separate study by the Bureau of Mines compares costs of utilizing coal gasification among several MHD configurations and conventional steam. Operating costs were higher, about 9 mills/kwhr for single-stage MHD, and nearly 10 mills/kwhr. for conventional steam. 10/ Capital costs were similar to those given by Rosa. The advantage of burning gasified coal is to reduce the technical problems and permit earlier application of MHD. Later, when more research has been completed, the switch can be made back to direct coal firing for greater economy.

The other major category of MHD system is the closed cycle liquid metal or closed cycle gas power plant. The basic feasibility of the liwuid metal system has been demonstrated and there are fewer technical problems than with open cycle systems. However, the performance and economy do not appear to be as attractive. This system will likely combine well with the Liquid Metal Fast Breeder Reactor.

The closed cycle gas MHD system utilizes a seeded noble gas such as argon as the working fluid. With this system, the electric fields enhance the conductivity by several orders of magnitude allowing the generator to operate at inlet temperatures as low as 3000°F. This permits more complete thermodynomic utilization of energy between the combustion temperature and the steam temperature in a combined MHD-steam plant. In addition, material problems through the system are significantly reduced. Based on preliminary work by General Electric in shock tube tests, efficiencies and costs are anticipated to be comparable to those for open cycle systems. 10/

Due to reduced temperatures and therefore, volumes of gases, the size and costs of a comparable closed cycle pilot plant would be as little as 1/10 that of an open cycle facility. A disadvantage of the closed cycle system is that the combustion gases are not seeded and therefore the sulfur removal process, which is inherent with the open cycle system, is lost. Also there are difficulties with heat exchanger design which need further attention.

While research has been largely confined to the laboratory, MHD has been receiving increased attention. Federal funding for fiscal year 1973 was on the order of $3 million with additional inputs from industry. Researchers are ready to begin construction of pilot plants capable of sustained runs of 1000 hrs and up.

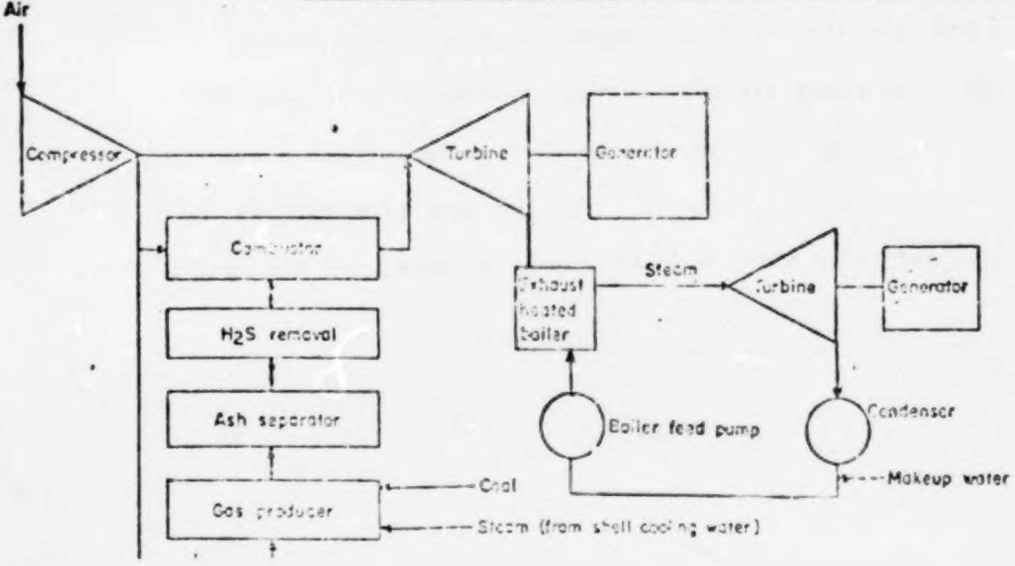
The above mentioned power cycles each show potential for improving the economics and reducing the environmental impact of electricity generation. Yet this advantage over current systems will be marginal unless they are ultimately coupled with another cycle to form a dual system as previously shown in figure 2. The two most prominent of the combined cycles, and those which will be discussed here, are the open cycle gas turbine-conventional steam cycle and the open cycle MHD - Conventional steam cycle.

Gas Turbine - Steam Cycle.

Current conventional steam cycles utilize the 3000°F coal combustion heat to produce 1000°F steam. A principle advantage of the combined cycle is that a turbine, operating at 1800-2000°F, can use this high temperature energy and still operate a 1000°F steam cycle sufficiently with the turbine exhaust. Also, unlike the steam cycle, it is probable that the temperature and pressure at the inlet of the turbine cycle can be increased in the next few years. This all tends to improve the efficiency, economy and reduce the environmental effects of the plant.

This arrangement is frequently coupled with a third component, a coal gasifier, to supply clean low-Btu fuel to the system. This is especially important in the U.S. which has ample coal resources and shortages of oil and gas. However coal gasification has not been considered economically attractive. The only currently available process is the Lurgi process which was developed several years ago in Germany. There is a considerable amount of research being done on newer processes which should be available in the early 1980's.

Fig. 4 Combined gas producer- gas turbine - steam cycle


Air
Compressor
Turbine
Generator
Combustor
H2S removal
Ash separator
Gas producer
Coal
Steam (from shell cooling water)
Exhaust heated boiler
Steam
Turbine
Generator
Boiler feed pump
Condenser
Makeup water

Presently, five companies are marketing preengineered combined cycle plants which are gas or oil fired. The facilities are designed to include the three classes of equipment: base-load, mid-range, and peaking generators. This pattern differs from the past practice of replacing base-load equipment and relegating older units to lower load factor use.11/ The first of these to be started up is the Commanche Station Public Service Co of Oklahoma. The 260 Mw plant has a predicted heat rate of 8540 Btu/Kwhr, or 40% efficiency. Capital costs for these packaged systems is in the range of $125 to $135/Kw. Additional advantages of such systems are their compact size, reliability, rapid startup (½ hr. from standby and 3 hrs. from cold iron condition), elimination of redundent capacity, short lead time for expansion and a decrease in thermal discharges. Although the last is true in comparison to conventional steam plants, there still is a need for some cooling water, thereby retaining the siting problem. A partial solution is to use the gas turbine for repowering an existing plant. Repowering refers to installing additional capacity in a plant by replacing existing boilers with gas turbines. Heat is still provided to the steam cycle while additional power is generated without additional space or cooling water. This is being planned by Southern California Edison for their Long Beach plant. For an estimated $160/Kw, capacity will increase from 148 Mw to 585 Mw and the heat rate is expected to drop from 14,500 to 9100 Btu/Kwh.12/

Larger proposed base load systems, which would include low-btu gasification of coal, are receiving more attention but require some further development before commercial application. An E.P.A. sponsored program would support construction of experimental plants initially using the Lurgi fixed-bed gasifier and existing gas turbine and steam cycle technology. Various components could be replaced as it was justified by improvements in that area. The table below indicates costs and efficiencies for three generations of technology. Conventional steam cycle figures are shown for comparison.

	1970's		1980's		1990's	
	Conventional	APC*	Conventional	APC*	Conv.	APC*
Efficiency, %	36.6	36.1	38.6	47.6	39.6	49.9
Capital Costs, $/Mw	174.8	167.5	160.7	127.3	160.7	124
Busbar Costs, Mills/Kwhr	6.23	7.23	5.76	5.24	5.72	5.14

*Advanced Power Cycle.

Progress on this combined cycle is dependent on development of gasifiers and improvements in gas turbine technology as mentioned earlier. Also needed will be improvements in coal mining techniques and mine safety.

The use of gas turbines in power generation is rapidly increasing in the U.S. In 1964 gas turbine installations constituted about 0.3% of total capacity. Presently it is about 7%. In a Federal Power Commission Report on utility plans through 1932, gas turbines were to make up 5.8% of the total planned capacity and combined cycles were to make up 2.3%.

The other major cycle to be considered here is the MHD - Steam combined cycle. This cycle has not reached the stage of development of the gas turbine combined cycle but maintains most of the same advantages

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over the conventional steam cycle. To reiterate, these advantages include improved efficiency, lowered capital and operating costs, lowered environmental impact, and more flexibility. MHD has the added advantage that coal can be fired directly, thus avoiding the additional step of gasification. MHD is a natural and perhaps ultimate refinement in expansion engines in that, unlike piston and turbine engines, there are no moving parts. Thus reliability is enhanced and maintenance is simplified. The most vulnerable of the components of the system to the high temperature operating conditions - the duct - can be of a simple and relatively cheap construction thus allowing it to be considered a throw-away item.

MHD - Steam cycle efficiencies are widely anticipated to be 50% for early designs and 60% for developed plants. Capital costs, while there is some disagreement, are generally below the conventional steam cycle or in the neighborhood of $200/Kw. Busbar costs are expected to be 6-10% below existing steam plants.

A final cycle to be mentioned is an MHD-gas turbine combination. While no express work is being directed to this concept, it does appear that high efficiencies should be possible and with no need for cooling water.

This discussion has attempted to address the more important aspects of Advanced Power technology although in many cases there is much uncertainty as to the states of the technology. More extensive research could reveal information about efforts in the areas of liquid metal turbines and liquid metal MHD generators, coal fired turbines and cyclone

MHD generators. More specific and up to date information on gasification, MHD and the various combined cycles would be helpful.

It seems likely that, after 2000, U.S. energy will be provided through fusion, solar, hydrogen, or some other "unlimited" source. Current programs are therefore focused on the intermediate term to bring us up to that period in which these technologies are available. Advanced power cycles should be carefully considered as to their potential in fulfilling these intermediate range requirements and contrasted with other programs. In comparison with the breeder reactor, the most heavily funded of current programs, the advanced power cycle appears to have less severe technical problems and minimal safety, environmental and social difficulties. Closer scrutiny of the overall relative merits of each program may suggest that a redistribution of funding is in order.

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DISCUSSION DRAFT--MARCH 1974

PART VII.

FUTURE ALTERNATE ENERGY SOURCES

GEOTHERMAL ENERGY
Summary

Approximately 2,000 megawatts of geothermally based electrical generating capacity is expected by 1980, about 4,000 megawatts by 1985 and about 40,000 megawatts by 2000. These estimates reflect development anticipated under current Government and industry programs extended into the future. However, submarginal geothermal resources, though for the most part not yet identified, are thought to be very large, and technological breakthroughs coupled with an acute need for energy could result in a faster rate of development. Geothermal energy is being utilized to a limited extent for space heating and a few other miscellaneous uses where low temperature heat is required. Such usage can be expected to increase. However, the heat must be used close to the source because of the heat loss and the expense incurred in piping hot water or steam any great distance. Because of this limitation the use of geothermal energy for space heating, etc., probably will be small in comparison to that for power generation.

In the Imperial Valley, and perhaps other areas, the hydrothermal systems comprised by geothermal reservoirs may become sources of fresh water as well as electric power. The economic picture for coproduction of power and fresh water in the Imperial Valley is brighter than that for production of power only. Recovery of minerals from geothermal brines also may prove to be economic.

With a few exceptions the areas prospectively valuable for geothermal resources are in the western third of the United States. Consequently, on a regional and local basis geothermal energy can make a significant contribution in the latter 1980's and 1990's even though it probably will account for only a very small portion of the Nation's total energy requirements.

Reserves/Resources [1]

The bulk of the Nation's known geothermal resource areas and promising areas are in the 12 western States plus Alaska and Hawaii. The question of where the United States geothermal energy resources are is easy to answer in the broad geographic context. Within this large region, however, the distribution, extent, magnitude and character of geothermal resources is only sketchily known.

As shown in Figure 1, geothermal reserve and resource estimates have been divided into several categories, according to feasibility of economic recovery and degree of certainty of the estimates.

The identified recoverable geothermal resources of the United States (excluding national parks) are estimated at 10^{16} Btu, based on an estimate of 6 x 10^{16} Btu in the ground, including measured, indicated, and inferred resources. This estimate includes the vapor-dominated reservoirs at The Geysers as well as several high-temperature hot-water reservoirs elsewhere in the western United States. As only about 15 percent of this is deliverable to the wellhead with current technology, the total reserves (at the wellhead) are thus 10^{16} Btu or enough steam to generate 1000 MW for 50 years at the current generating efficiency of 14 percent.

Undiscovered recoverable geothermal resources (defined as those resources recoverable at cost competitive with alternative forms of energy) are estimated at 6 - 12 x 10^{16} Btu at wellhead. This amount of geothermal energy would support 3000-6000 MW of generating capacity for 50 years, using proven and conventional technology. The geothermal

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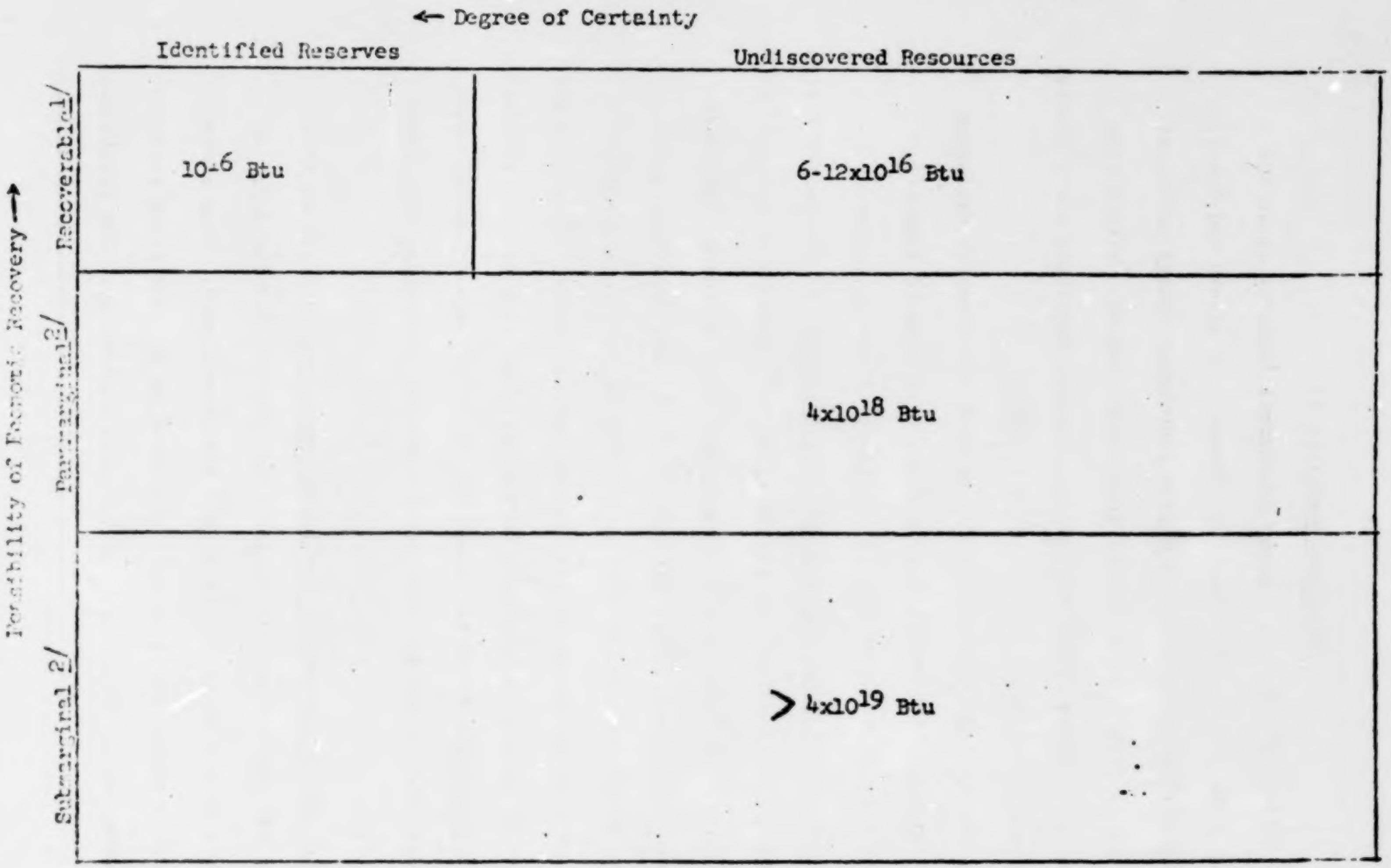
[1] Source: Geological Survey



← Degree of Certainty
Identified Reserves
Undiscovered Resources
Feasibility of Economic Recovery →
Recoverable 1/
Paramarginal 2/
Submarginal 2/
10^{-6} Btu
$6\text{-}12\times10^{16}$ Btu
4×10^{18} Btu
$> 4\times10^{19}$ Btu

1/ figures shown are energy at the well head

2/ figures shown are energy in situ

Figure 1. Estimated reserves and resources of geothermal energy

reservoirs included in the estimate must have temperatures of at least 180° C (356° F), because at lower temperatures the quantity of flash steam is inadequate. Reservoirs included would be vapor-dominated and high-temperature hot-water systems.

Paramarginal resources are estimated at 4×10^{18} Btu in situ, sufficient to support 40,000 MW generating capacity for at least 50 years. These resources would consist largely of high-temperature (180° C, 356° F) hot-water systems that might be developed economically at the present time or in the near future. Kilkenny estimates that whereas 7,000 MW of geothermal generating capacity can be expected by 1985 using present utilization technology, successful application of a secondary fluid, such as freon (at somewhat higher costs) can result in the installation of an additional 12,000 MW, or a total of 19,000 MW by 1985. 2/

Recoverable geothermal resources could be expanded by technological breakthroughs that would permit the economic development of resources that are clearly not economic at the present time. These submarginal resources are estimated to be more than 4×10^{19} Btu and sufficient to support more than 400,000 MW generating capacity for 50 years.

By way of comparison, the total U.S. installed electrical generating capacity in 1971 was 367,395 MW and is forecast at 1,880,000 MW in 2000.

2/ In material prepared for NPC's New Energy Forms Task Group for U.S. Energy Outlook Study

In connection with the Geothermal Steam Act of 1970, the Geological Survey has classified a large number of areas in the western States and Alaska as known geothermal resource areas (KGRAs) and areas valuable prespectively for geothermal resources. To date about 1.8 million acres have been identified as KGRAs. In addition, approximately 96 million acres have been classified as valuable prospectively for geothermal resources. Approximately 60 percent of this acreage is on public lands. The KGRAs and prospective areas, except those in Alaska, are shown in Figures 2 and 3. The names of the KGRAs, designated by number on these illustrations, are given in table 1:

Table 1-Known geothermal resources areas

Locality	Name
	California
1	The Geysers
2	Salton Sea
3	Mono-Long Valley
4	Calistoga
5	Lake City
6	Wendel-Amedee
7	Coso Hot Springs
8	Lassen
9	Glass Mountain
10	Sespe Hot Springs
11	Heber
12	Brawley
13	Dunes
14	Glamis
	Idaho
1	Yellowstone
2	Frazier
	Montana
1	Yellowstone
	Nevada
1	Beowawe
2	Fly Ranch
3	Leach Hot Springs
	Nevada (Continued)
4	Steamboat Springs
5	Brady Hot Springs
6	Stillwater-Soda Lake
7	Darrough Hot Springs
8	Gerlach
9	Moana Springs
10	Double Hot Springs
11	Wabuska
12	Monte Neva
13	Elko Hot Springs
	New Mexico
1	Baca Location No. 1
	Oregon
1	Breitenbush Hot Springs
2	Crump Geyser
3	Vale Hot Springs
4	Mount Hood
5	Lakeview
6	Carey Hot Springs
7	Klamath Falls
	Utah
1	Crater Springs
2	Roosevelt
	Washington
1	Mount St. Helens

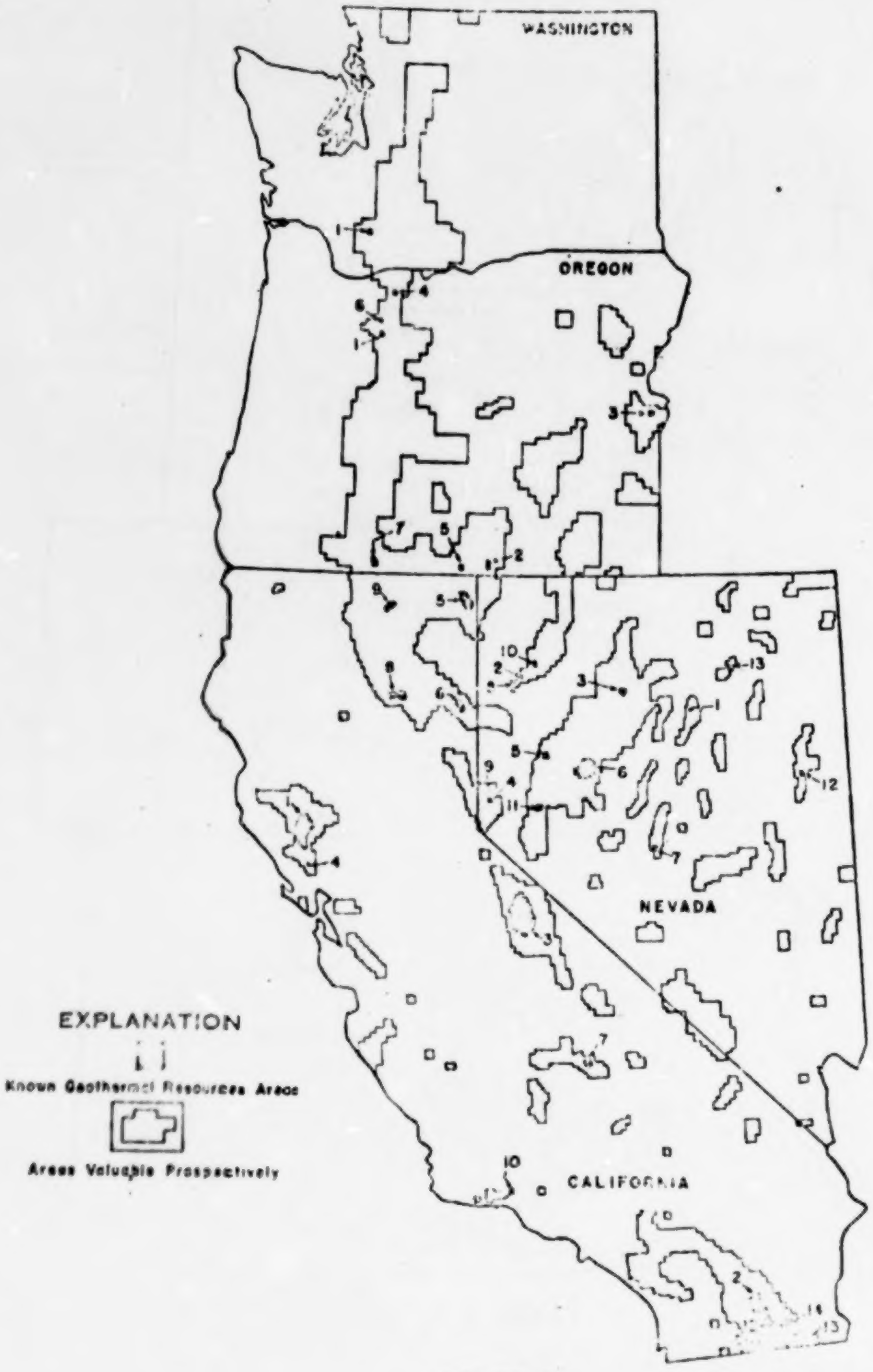

WASHINGTON
OREGON
NEVADA
CALIFORNIA
EXPLANATION
Known Geothermal Resources Areas
Areas Valuable Prospectively

FIGURE 2.

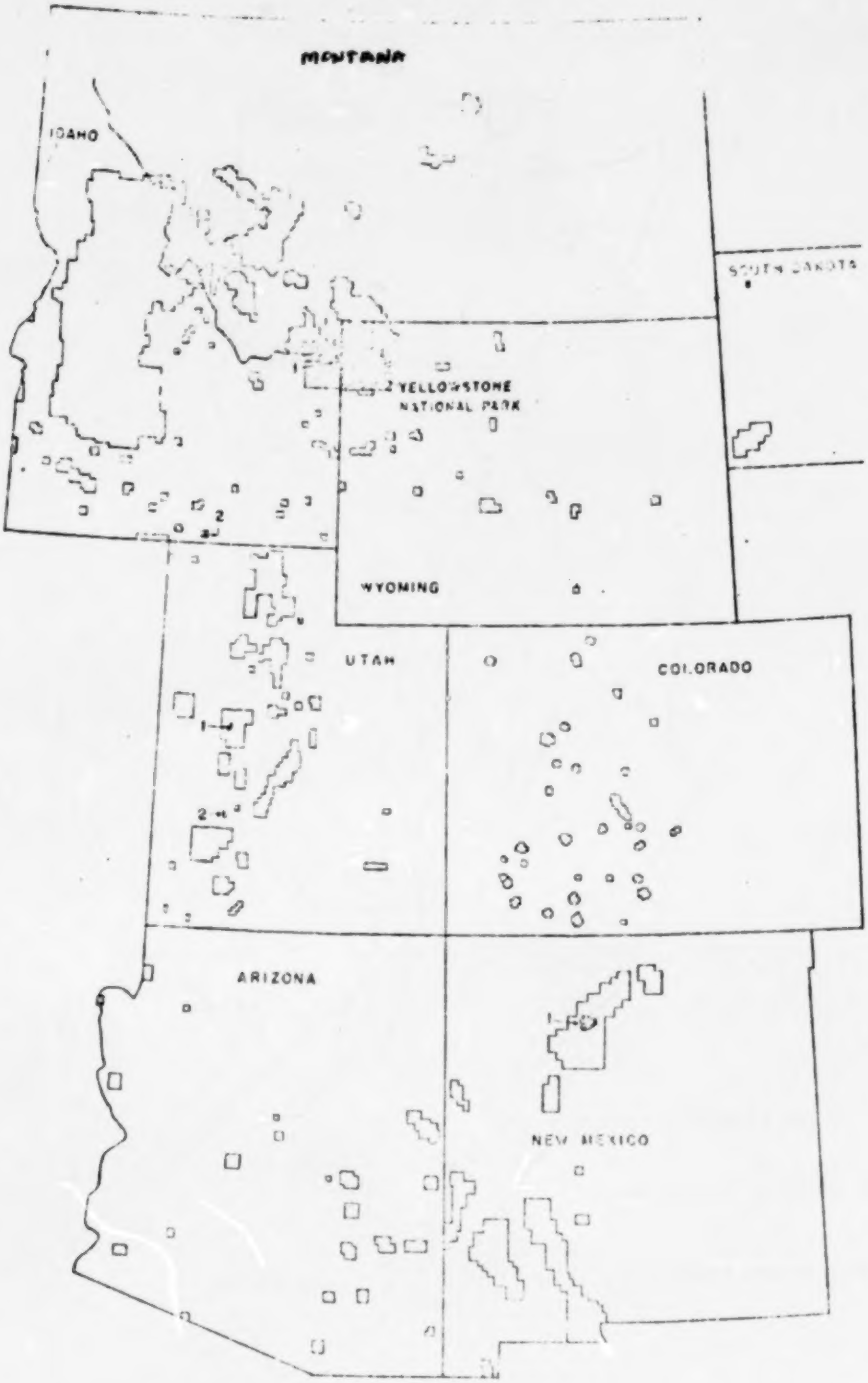

MONTANA
IDAHO
SOUTH DAKOTA
YELLOWSTONE NATIONAL PARK
WYOMING
UTAH
COLORADO
ARIZONA
NEW MEXICO
2
1
2

FIGURE 3.

Technology--Status and Possible Advances

The technologies of finding, recovering and utilizing geothermal energy are in an early stage of development. At The Geysers geothermal field in northern California, some 80 miles north of San Francisco, the first generating unit (11,000 Kw) went into operation in 1960. Progressively larger units (13,000 Kw and 27,000 Kw) were placed in operation in 1963 and 1967. The first 53,000 Kw units went into operation in 1971 and others of this size have been added since then. A 106,000 Kw unit is under construction.

The Geysers installation is the only commercial geothermal electric power installation in the United States. It is apparent, therefore, that our background of experience and technology relative to geothermal energy is scant. Furthermore, The Geysers is not typical of most geothermal fields that probably will be developed in the United States. It is a dry steam (vapor dominated) system whereas nearly all the other hydrothermal fields in this country are thought to be superheated hot water (liquid dominated) systems and lower temperature hot water systems. Technological development will be required also for other types of geothermal systems, namely, masses of hot dry rock and geopressured fields.

There are a number of geothermal power installations in other countries. Geothermal energy also is being used to a very limited extent for other purposes.

The present uses of geothermal resources include power generation, space heating, agriculture, refrigeration, industrial processing, production of fresh water by desalination, and byproduct chemical, mineral, and gas resources. The following list provides some present day examples of the worldwide use of geothermal resources:

Electrical Power

United States

The Geysers, California - 404 MW (1973)

World

Larderello, Italy - 390 MW
Monte Amiata, Italy - 26 MW
Wairakai, New Zealand - 192 MW
Matsukawa, Japan - 20 MW
Otake, Japan - 12 MW
Cerro Prieto, Mexico - 75 MW (1973)
Pathe, Mexico - ½ MW
Namafjall, Iceland - 3 MW
Pauzhetsk, USSR - 5 MW

Space Heating

United States

Klamath Falls, Oregon	over 400 buildings
Boise, Idaho	over 200 homes

World

Iceland
New Zealand
Hungary
USSR

Manufacturing and Processing

Iceland
New Zealand
USSR

Refrigeration

USSR

Byproduct Chemicals

USSR

Desalination
Imperial Valley, California (Experimental)

All the geothermal experience to date, however, represents only a minor amount of the technology development and application that will be required if geothermal energy is to play an appreciable role in supplying the energy needs of this country.

The general extent of the resource in the western states can be inferred from the distribution of hot springs, and in a more general way from the distribution of young volcanic rocks. In the past, geothermal exploration has been primarily on sites identified by hot springs (an exploration method analogous to the primitive oil exploration methods of the turn of the century, when oil fields could be located only by finding surface oil seeps). Geologic and geochemical techniques are only now beginning to be adapted to geothermal exploration.

Knowledge of the character and parameters of individual geothermal systems has come from exploratory drilling, from limited developmental drilling (mainly at The Geysers of Northern California and at the Salton Sea area in Southern California), and from limited studies of major thermalspring areas, supplemented by shallow research drilling. Extrapolation of knowledge from other countries, mainly New Zealind, has proved useful, but techniques for estimating the size and power potential of geothermal sites prior to drilling are only beginning to be developed. Techniques for efficiently utilizing all of the energy produced from geothermal wells (e.g., by desalination or by 2-phase generation) are only beginning to be investigated and developed.

GEOTHERMAL POWER PLANTS

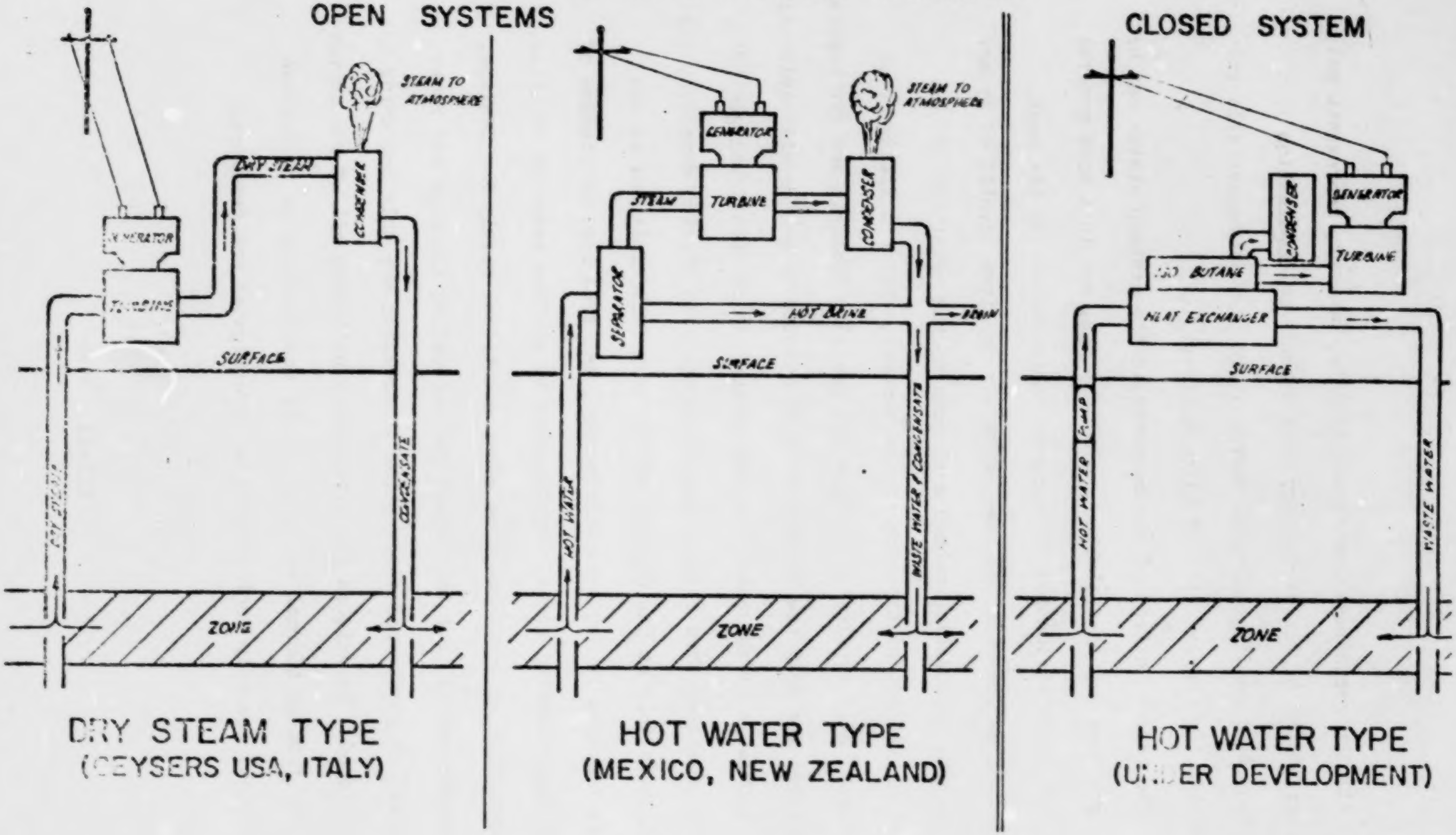

OPEN SYSTEMS
CLOSED SYSTEM
STEAM TO ATMOSPHERE
GENERATOR
TURBINE
DRY STEAM
CONDENSER
SURFACE
CONDENSATE
ZONE
STEAM TO ATMOSPHERE
GENERATOR
STEAM
TURBINE
CONDENSER
SEPARATOR
HOT BRINE
DRAIN
SURFACE
HOT WATER
WASTE WATER & CONDENSATE
ZONE
CONDENSER
GENERATOR
TURBINE
ISO BUTANE
HEAT EXCHANGER
SURFACE
PUMP
HOT WATER
WASTE WATER
ZONE
DRY STEAM TYPE
(GEYSERS USA, ITALY)
HOT WATER TYPE
(MEXICO, NEW ZEALAND)
HOT WATER TYPE
(UNDER DEVELOPMENT)

Figure 4

GEOTHERMAL POWER AND DESALINATION PLANTS

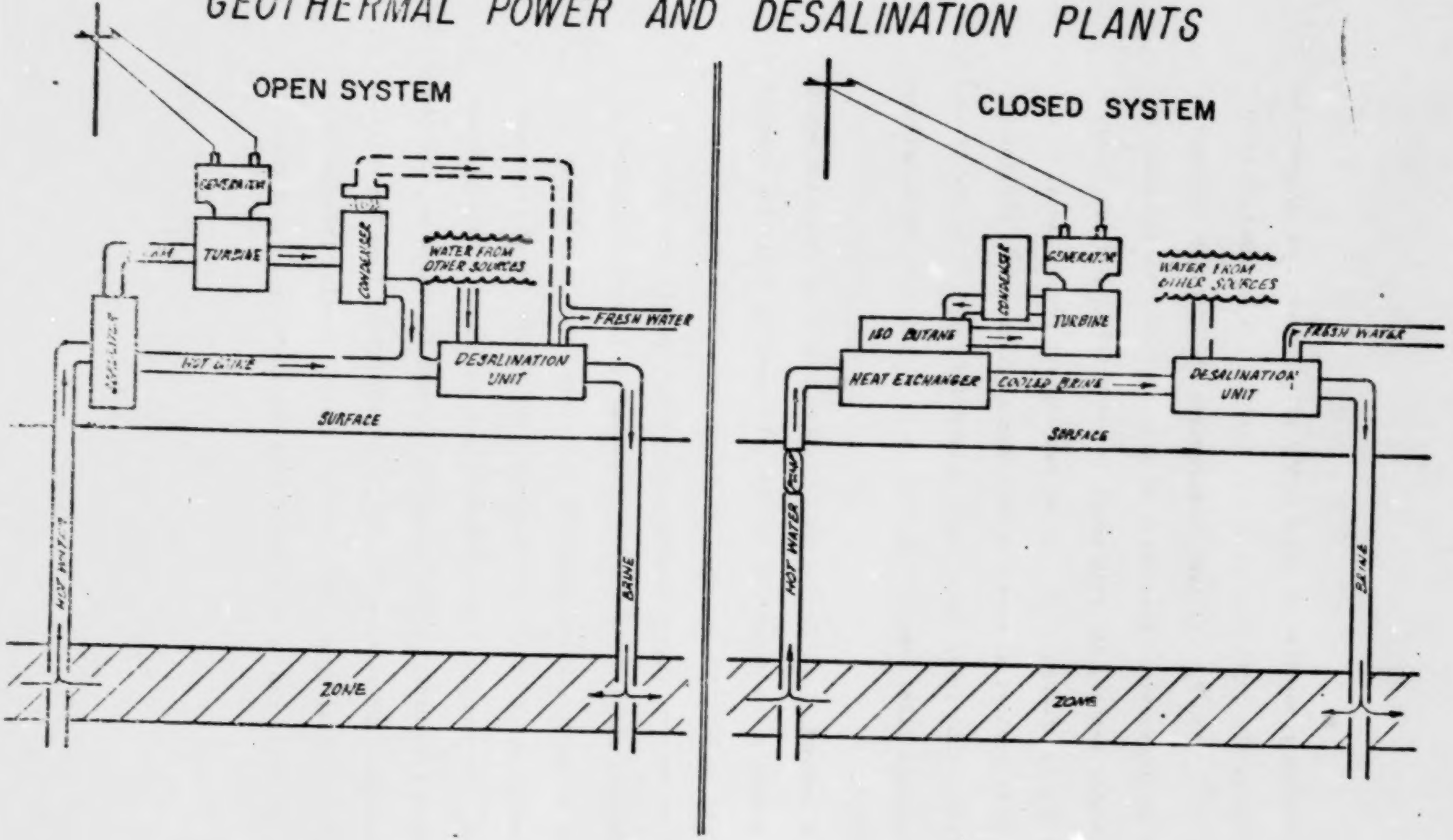

OPEN SYSTEM
GENERATOR
TURBINE
CONDENSER
WATER FROM OTHER SOURCES
FRESH WATER
HOT BRINE
DESALINATION UNIT
SURFACE
HOT WATER
BRINE
ZONE
CLOSED SYSTEM
CONDENSER
GENERATOR
TURBINE
WATER FROM OTHER SOURCES
ISO BUTANE
FRESH WATER
HEAT EXCHANGER
COOLED BRINE
DESALINATION UNIT
SURFACE
PUMP
HOT WATER
BRINE
ZONE

Figure 5

For the generation of electricity using proved and demonstrated technology, the geothermal reservoir must have a temperature of at least 180°C (356°F); at lower temperatures the quantity of flash steam is inadequate. Reservoirs at this or higher temperature, at recoverable depths, and with adequate productivity are not likely to be highly abundant. Widespread development seems likely, then, only if technological advances that would make possible electrical generation from lower temperature waters are realized and/or if energy applications other than the generation of electricity are considered desirable.

A technological innovation currently receiving attention would make possible the generation of electric power by utilizing some of the heat in water at temperatures below its atmospheric boiling point as well as higher temperature water. In this new system, a low boiling point fluid such as isobutane or freon is vaporized in a heat exchanger, which transfers heat from water supplied by geothermal wells to the low boiling point fluid. In an isobutane system, for example, the isobutane vapor builds up enough pressure to drive a turbine. After expanding through this turbine, the isobutane is condensed and returned to the heat exchanger. Then the cycle is repeated. Water from geothermal wells after passing through the heat exchanger can be reinjected into the geothermal reservoir.

If the new technology proves to be economically viable, it would apply to geothermal reservoirs whose temperatures are too low for steam production. It would also make possible utilization of a greater portion of the heat than that possible with present technology in higher temperature hydrothermal systems. The low boiling point fluid process also may offer a means of reducing scaling and corrosion problems in power generation plants using hot water with very high dissolved mineral content. Figure 4 illustrates three types of power plants, namely dry steam, hot water partially flashing to steam, and the dual fluid (low boiling point fluid) type.

In the Imperial Valley, production of fresh water to augment the flow and reduce the salinity of the Colorado River is contemplated and a program of pilot investigations related thereto has been undertaken. Recovery of minerals from the brine also is a consideration. Fresh water and minerals from geothermal developments in some other areas also may warrant pilot investigations. Figure 5 shows flow patterns for recovery of fresh water as well as power.

Beneath the northern Gulf Coast is a geopressured field, a sedimentary basin in which interstitial hot water is confined under high pressure. Sedimentary basins of this type at other locations in the United States are known but they appear to have less appeal at the present time.

The geothermal energy in these sedimentary basins may represent a significant resource potential. However, determination of its significance must wait resource assessment studies, demonstration of recovery technology, and determination of economic feasibility.

Hot dry rock represents a very large potential geothermal energy resource. Recovery of heat from this source is not economic at present. Determining its significance as a future energy source will depend, among other things, on (1) ascertainment of the availability of rock at sufficiently high temperature at depths less than 10,000 feet, assuming present drilling techniques, and (2) development of technology for recovering energy from dry hot rock. Conceptual studies of recovery methods have been made. Basically, these methods involve fracturing the rock to provide passageways, injecting water into the fractured area, heating of water (and steam in some instances) by the hot rock, and using the energy absorbed by the water (or steam) to generate electric power.

Development of new drilling techniques that would allow economical drilling to greater depths conceivably could bring large quantities of presently submarginal resources within reach. Temperatures increase with depth; expense and problems involved in drilling do also.

Geothermal Power Estimates through Year 2000

The greatest potential for geothermal energy exists in the western part of the United States. This encompasses the Mountain and Pacific regions. 3/ In 1971, the installed capacity and net generation of this area was as follows:

Area	Installed Capacity (Megawatts)	Net Generation (Million KW-hrs)
Mountain	19,010	80,034
Pacific	47,974	230,925
Total	66,984	310,959

As could be expected, the greater bulk of the generating capacity and generation in the area is located specifically in the Pacific area.

In the future the electrical generating capacity requirements in these regions with high geothermal potential and in the entire United States will be as follows:

	Capacity Requirements 2/ (Megawatts)			
Year	Mountain Region	Pacific Region	Total Mountain & Pacific	Total U.S.
1975	27,500	79,200	106,700	480,000
1980	35,200	100,800	136,000	660,000
1985	49,600	141,200	191,000	915,000
2000	120,000	360,000	480,000	1,880,000

2/ Based on National Power Survey, FPC. 20 percent reserve requirements assumed.

3/ The Mountain region consists of Arizona, Colorado, Montana, Nevada, New Mexico, Utah, and Wyoming. The Pacific region consists of California, Oregon, and Washington.

By 1975, geothermal power in the Geysers area of California is expected to approximate 660 megawatts. Between now and 1980, some 1,340 additional megawatts are estimated to come on the line. Between 1980 and 1985, an additional 2000 megawatts of capacity is forecast to come on the line. An additional 36,000 megawatts of capacity has been projected between 1985 and 2000. The 75 capacity figures are based on plants already on order, while the capacity between 1975 and 1985 is based on the known reserves of geothermal energy. It was assumed that a power plant would last for 30 years; hence, division of the known reserves by 30 gave the energy available for power. This, in turn, was divided by the heat rate (in Btu's/KW-hr) to give the capacity that could be supported by known reserves. This resulted in an adjusted figure of approximately 4,000 megawatts. The 1985-2000 capacity figures result from an arbitrary assignment of approximately 15 percent of extra capacity to geothermal.

The resulting estimate of geothermal electric power is as follows:

1975	660
1980	2,000
1985	4,000
2000	40,000

Common denominator units will probably be useful in considerations involving relationships between geothermal energy and energy from other sources. Because of the low pressure of geothermal steam, heat rates are higher (efficiencies lower) than for power plants based on oil or coal. Table 2 shows the heat consumption represented by geothermal steam flowing through turbines (heat rate 21,690 Btu/Kwhr), the corresponding heat consumption for oil-fired generating facilities, (heat rate 10,500 Btu/Kwhr) and the oil equivalent or amount of oil that would be required to generate the amounts of power shown in the table.

Table 2. -- Btu and Oil Equivalent Quantities

	Installed Capacity (Mw)	Annual Geothermal 1/ 2/ heat consumption (Trillion Btu)	Annual heat consumption for equivalent oil fired 3/ 4/ facilities (Trillion Btu)	Daily Oil Equivalent 5/ (Million barrels
1980	2,000	304	147	.070
1985	4,000	608	294	.139
1990	9,000	1,368	662	.313
2000	40,000	6,080	2,943	1.390

1/ Load factor of 0.80 assumed.

2/ Heat rate of 21,690 Btu/Kwhr (same as at The Geysers) assumed.

3/ Load factor of 0.80 assumed.

4/ Heat rate of 10,500 Btu/Kwhr.

5/ Heating value of 5.8×10^6 Btu/bbl.

The importance of anticipated geothermal developments under the abovedescribed scenario in relation to the forecast national and regional energy requirements and electrical generating capacities is indicated by the following tabulation:

	1975	1980	1985	2000
Geothermal energy input as % of total U.S. energy input	0.1	0.3	0.5	3.1
Geothermal as % of total U.S. electrical generating capacity	0.1	0.3	0.4	2.1
Geothermal as % of Mountain and Pacific electrical generating capacity	0.6	1.5	2.1	8.3

Geothermal energy is not expected to play an important role in supplying a major portion of U.S. energy needs through the rest of this century. From a regional standpoint however, it is expected to become significant.

Estimates of the ultimate potential of The Geysers geothermal field vary widely. According to a recent statement, it could approach 2,000 Mw. Other estimates are stated as 1,000 to 4,000 Mw. According to one estimate, based largely on theoretical studies, as much as 25,000 Mw may be possible.

Generating capacity at The Geysers, now around 400 Mw, is expected to increase to 900 Mw by the end of 1977 It is assumed that the capacity in 1985 will be 1,500 Mw. Accordingly, generation of 2,500 Mw of geothermal power in 1985 at other locations in 1985 is anticipated.

The 2,500 Mw are assumed to be derived from superheated hot water installations.

Scenarios other than the one presented above have been portrayed by individuals and groups involved in geothermal studies. Their views as to the possible and probable amounts of geothermal energy that may be expected in the United States during the remainder of this century, span a wide range. The low figures tend to be based on the continuation of existing technology and the development of relatively few new fields. The high figures are based on optimistic assumptions concerning total resources, on considerable research and development funding, and on significant breakthroughs in technology. Future geothermal capacity over the minimum estimates is contingent on both resource development and technological breakthroughs.

Government Programs

Development of geothermal resources is being encouraged by the leasing of public lands underlain by geothermal reservoirs. The Federal Government also is conducting research and development aimed at improving and accelerating the means and procedures for finding, developing and utilizing geothermal resources. Some States, particularly California, too are lending encouragement to developers of geothermal fields.

About 60 percent of the known geothermal resource areas (KGRAs) and areas valuable prospectively for geothermal resources (PGRAs) are on public lands. The Geothermal Steam Act of 1970 authorized the leasing of public lands and certain other lands administered by the Federal Government for the development and utilization of geothermal steam and associated resources. The Act includes provisions for competitive bidding on lands to be leased within any KGRA. Only the Federal lands within any KGRA are subject to leasing under the Act. PGRA lands can be leased on a non-competitive basis.

The first lease sales were held on January 22 of this year on some 50,000 acres in three KGRAs in California -- namely, the Clear Lake - Geysers area, the Mono Lake - Long Valley area and the East Mesa area of the Imperial Valley.

Prior to announcement of the lease sale a final environmental impact statement was released. Also, leasing and operating regulations were developed and published in the Federal Register.

ECONOMICS

As is true of presently installed capacity, the bulk of future geothermal capacity in the area of high geothermal potential will lie in the Pacific region. This would indicate limitation on geothermal energy unless the geothermal power plant is either: (a) substantially closer to the load centers; or, (b) substantially lower in production costs, thus enabling transmission costs to be absorbed. Geothermal energy is a viable heat resource only when the total costs of producing and distributing this power is lower than the total costs of producing and distributing power produced from other energy sources, given equal environmental impact.

Estimates of the cost of producing electrical power from various energy sources is as follows:

Power Plant Type	Power Costs mills/KW-hr
Geothermal (Dry Steam)	5.25[4]
Gas Fired	6.7
Coal Fired	8.2
Hydroelectric	9.6
Nuclear	9.6
Geothermal (Hot Water)	9.7
Oil Fired	10.0

The above power costs, detailed in Tables 3 and 4 are valid only for the western area of the country, and are based on adjustments to 1972 figures. In all instances, it is assumed that the plant built will be at or near the scale frontier, i.e., the plant will represent the largest possible plant of that type with existing technology. For various technical

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4/ U.S. Energy Outlook, 1972

reasons, the geothermal power plants will be small units; hence, transmission cost would normally be higher for moving this power from the source to the load. This does not mean that geothermal energy cannot successfully compete with other energy sources for generating electricity. The cost of transmission also works in favor of geothermal in those areas where loads are small and isolated. The small size of the producing unit limits any economies of scale normally available from most other electrical plants, and the remoteness of production would mean the power shipped in would normally have higher transmission costs, thus decreasing competitive output from geothermal power plants. For these reasons, it is expected that the competitive output of geothermal plants will be highest in the mountain states, and that most long-term development should occur there.

Table 3. - Geothermal Plant Investment and Annual Fixed Charges 1/

Item	Value	
Unit Costs of Investment	10-year life	30-year life
Production Well System	$48	$25
Injection Well System	75	32
Make-up Water System	7	8
Sub-total: Steam Winning System	130	65
Generating Plant 2/	0	95
TOTAL	130	160
Annual fixed charges, percent of investment 3/	23	17

1/ Steam-winning costs based on Geothermal Resources Investigation, January 1972, by Bureau of Reclamation. escalated to reflect inflationary trends in construction industry.

2/ Includes structures, turbine generators, electrical equipment, miscellaneous. Excludes land, steam-winning system, switchyard.

3/ Includes cost of money, depreciation, interim replacement, insurance and taxes.

Table 4. - Cost of Electricity from Variously Fueled Plants

Item	Gas-fired Power Plant 1/	Coal-fired Power Plant 2/	Hydro-Electric	Nuclear Power Plant	Geothermal Power Plant (Hot water)	Oil-fired Power Plant 1/
Unit investment cost of plant, $/KW 3/	105	225	390	300	4/ 290	115
Annual fixed charge, percent of investment 5/	17	17	17	17	4/	17
Kilowatt-hours generated per year per KW capacity 6/	7,000	7,000	7,000	7,000	7,000	7,000
Heat Rate 7/	10,000	9,500	-	10,600	15,700	10,500
Cost of fuels, cents/million Btu	34.8	20.3	-	17.5	8/ 37.6	61.5
Cost of Electricity						
Plant investment	2.6	5.5	9.5	7.3	2.3	2.8
Operation & Maintenance	.6	.8	.1	.4	1.5	.7
Fuel	3.5	1.9	-	1.9	5.9	6.5
Total	6.7	8.2	9.6	9.6	9.7	10.0

1/ Outdoor type plant.
2/ Indoor type plant. All figures valid only for western states.
3/ Includes Land, structures, boilers, turbine generators, electrical equipment, miscellaneous plant equipment. Excludes switchyard.
4/ See Table 3 for explanation of investment costs and annual fixed charges.
5/ Includes cost of money, depreciation, interim replacements, insurance, and taxes.
6/ The 80 percent operating factor used here is applicable only to base load plants. Hydro is seldom a base load plant.
7/ Varying heat rates representative of power plants under consideration when base loaded.
8/ Cost of fuel based on capital and operating costs of steam-winning system.

Problems

Some of the problems that could servely restrict the rate of development of geothermal energy have been mentioned, such as the present lack of adequate knowledge and experience in the field and the fact that most of the prospective geothermal areas are rather far from large load centers. There are a few additional areas of concern, and this section elaborates somewhat on the problems likely to be encountered.

Following is an excerpt on problems from the report of the NPC task group that worked on geothermal energy in connection with the recent study on U.S. Energy Outlook:

"There are a number of problems that may act as deterrents to companies contemplating geothermal exploration. One of these is the long delay between the time of completion of the first well and the time that the plant goes on production. The cost of plant construction is the largest item in the development of geothermal power, and the turbines, because of special construction, must be ordered several years in advance. Several confirmation wells (semi-exploratory) are usually needed before initial steps are taken to build the plant. In The Geysers Field, some wells drilled 5 years ago are not yet on production at this writing. It is estimated that there will be about a 2-year delay for wells currently being drilled.

A second problem is that of dissolved minerals. Of all the exploratory wells that have been drilled to date in the United States, only The Geysers has been relatively free of dissolved minerals in the effluent. One of the best examples of the problem can be seen in the Niland or Buttes Field in the Salton Sea area of the Imperial Valley, where all wells produce a brine with about 25-percent salts, creating problems of corrosion, scaling and effluent disposal. Scaling (deposition of $CaCO_3$, or SiO_2), is a problem in nearly every well that has produced hot water. Other constituents of geothermal fluids are hydrogen sulfide, fluorine, boron, carbon dioxide and arsenic. The best solution to scaling appears to be the "heat exchange" method where the produced hot fluids are kept under pressure and returned to the ground. Corrosion can be due to acidic or alkaline conditions.

At The Geysers, ammonia and boron are present in the steam effluent in small quantities, and because of this the fluid is currently, and will continue to be, injected into otherwise unused wells on the edge of the field.

The dissolved minerals in the effluent, in addition to causing problems with the operator's equipment, are also a source of pollution. Boron is harmful to agriculture and ammonia is injurious to small fish life.

A third problem involves noise from geothermal operations during the drilling and testing of wells which can be annoying to nearby residents. The noise of steam escaping from the discharge line can be deafening at close distance due to tremendous velocities of flow. Mufflers have been designed and are being improved which will remedy this problem."

Another indication of the time required for development drilling and plant construction is given by Chester F. Budd of Union Oil Company's Geysers operations, as follows:

> "Under current California Public Utility Commission regulations, utility companies are required to submit applications for plant sites 1 year in advance of commencing construction, which in practice means at The Geysers about 4 years before anticipated operation. The required steam supply, moreover, must be available for about 1 year to allow for pipeline construction. Thus, Thus, allowing time for evaluation subsequent to discovery, a lead time of 5 years between confirmation drilling and commercial operation is required. All of these delays combine to lower the rate of return on the investment."

Environmental problems associated with geothermal energy may not be as severe as those for most other sources of energy. However, when the industry grows to maturity it will encompass rather large geographic areas.

Of particular concern to many environmental groups is the alteration of aesthetic qualities of an area due to industrial development. It is expected that geothermal developments may be limited in certain areas to avoid or minimize major land use conflicts. As future developments are planned, it is expected that public hearings will be held to establish a complete record where significant changes are proposed.

The recently released final environmental impact statement gives full information on environmental considerations for the three areas in California initially being opened to leasing. Following is an excerpt from the Summary: "Lands under consideration for geothermal leasing presently are subject to use for grazing, forestry, mining and other mineral production, fish and wildlife habitat, outdoor recreation, and watershed. Development of geothermal resources entails construction of access roads and well sites, drilling and testing of wells, conveyance of steam over short distances to electric power plants and by-product facilities, electrical transmission lines, and facilities, electrical transmission lines, and facilities for disposing of wasteliquids. Locally, land would be preempted or restricted from uses such as wildlife habitat, recreational use, grazing, etc. Terrain would be modified through construction of roads, wells, pipelines, and industrial facilities. Noise and noxious gaseous emmissions could pose problems during testing and production. Possible adverse effects include land subsidence due to production of fluids and increased seismicity due to production and reinjection of fluid wastes into producing zones.

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SOLAR ENERGY

Solar energy is generally considered to be an environmentally acceptable energy source. It can make a major contribution to the future energy needs of the Nation and give more options when an energy source is being selected for a particular purpose or region. Solar energy is utilized today only in a limited extent.

Although solar energy systems have been shown to be feasible, the utilization of solar energy on a relatively significant scale is not expected until 1985 or later. Research and development are needed to improve the technology to collect and concentrate solar energy because it reaches the earth's surface at relatively low intensities (Figure 1). In addition, the technology for storing solar energy must be improved because solar energy is available only during part of the day and during periods of clear skies (Figure 2). Work is also needed to assure the availability of basic materials, such as high-purity silicon material, and to develop new materials. Also, appropriate manufacturing and servicing companies need to be developed to support a solar energy industry.

The proposals for utilizing solar energy include: solar energy collectors on roofs that would supply energy to heat and cool buildings; photovoltaic systems that would convert solar energy into electricity; parabolic reflectors and/or optical systems that would concentrate solar energy to provide steam for turbines and intense heat for other purposes; a large terrestrial solar powerplant that would collect solar energy for subsequent conversion to electricity; a satellite station that would collect and transmit solar energy to earth for conversion to electricity.

In general, the use of solar energy to heat and cool buildings is considered to have the most potential for near-term realization. According to an assessment of solar energy as a national energy resource, prepared in December 1972 by the National Science Foundation (NSF)/National Aeronautics and Space Administration (NASA) solar energy panel, the use of solar energy in buildings is envisaged as becoming relatively significant in 1985. In that year the panel estimates that if 10 percent of the new buildings contained solar energy systems, the estimated national energy savings would be equivalent to about 120 trillion Btu. In the year 2000 the energy savings would be an estimated 2,100 trillion Btu if 50 percent of the new buildings had solar energy systems.

The concept of using solar energy for residential heating has been studied for more than 30 years. All the systems developed need auxiliary heating systems; electricity is needed to circulate heated air or water. The costs of solar heat for a house, as calculated in 1961 and excluding the cost of the equipment, ranged from $1.10 to $4.64 per million Btu, depending on the location (Table 1 and Figure 3). Based on 1970 prices, conventional heating costs range from $0.85 to $5.25 per million Btu. It is significant to note that the cost of the solar equipment in 1961 was considered uneconomical, that the solar-heating systems needed various amounts of auxiliary heat, and the price comparisons for the solar energy equipment are probably not valid today.

The technology of using solar energy for residential cooling systems is less developed than that for heating systems. Although an estimate of the costs are not available, solar cooling by absorption techniques is considered to be economically viable if it is incorporated into a solar heating system. Such a combination would enable a system to be used at a reasonable capacity throughout the year. Proposed energy storage systems include hot water, hot rock, and chemicals.

Electricity can be generated from solar energy, but the estimated costs are very high and not competitive with present-day steam powerplants (Table 2 and Figure 3). Solar radiation can be converted directly into electricity through the photovoltaic effect. The heat of solar radiation can be concentrated and collected and used to fuel a conventional powerplant. In both cases power is available only when the sun shines. Solar power generation without energy storage facilities could be used for "peaking" applications. If the solar power is to be utilized at all times, low cost methods are needed for storing the energy. One type of storage facility would store heat, which would be withdrawn at a constant rate, or on demand, to operate a powerplant. Another type would store electrical energy. A third possibility is that the solar energy might be used to generate a chemical fuel such as hydrogen or oxygen.

The NSF/NASA panel estimates that electric power generation by photovoltaic solar energy systems has the most promise for near-term realization. In photovoltaic systems, which use silicon solar cells, the absorption of light generates free electrical charges that can be collected. The average efficiency of the solar cells ranges from

11 percent for cells used in satellites to a high of about 16 percent for certain cells still in the development stage. The theoretical limit of efficiency is about 25 percent for a single-semiconductor device operating at room temperature. According to the NSF/NASA panel, the price of solar cells would have to be reduced by a factor of at least 100 from present levels to make silicon solar arrays economically feasible for widespread use. Additional research is needed to determine the suitability of other semiconductor materials for solar energy applications. A combination of solar cells and flat plate thermal collectors has also been considered to have potential.

However, the NSF/NASA panel estimates that photovoltaic systems will have an impact of only one percent or less on the Nation's energy requirements in 1985. Solar thermal conversion systems in large power-plants are viewed as long-term goals that will have significance after the year 2000. The panel estimates that 10 percent of the new power-plants constructed after the year 2000 could be solar plants.

In summary, solar energy has a role as a contributor to the Nation's future energy supply. It is not expected to make a significant contribution until about 1985, when it could supply the equivalent of 120 trillion Btu for heating and cooling buildings. Wider application of solar energy is expected to be achieved beginning in the year 2000.

To achieve the use of solar thermal energy for buildings by 1985, the NSF/NASA panel recommended R & D funds of $100 million over 15 years. Similarly, during the same period, the panel recommended a funding of $1,130 million for R & D pertaining to electric power generation by solar thermal conversion, and $780 million for photovoltaic conversion.

Because of the high costs of bringing solar energy to the point of widespread use, private industry cannot be expected to engage in large-scale research and development. Substantial Government support will be needed. In Fiscal Year 1975 about $50 million will be made available in Government-sponsored solar energy programs. This compares with $12 million in Fiscal Year 1974 and $3 million in Fiscal Year 1973.

Table 1. Costs of space heating (1970 prices) in dollars per million Btu useful delivery

Location	Optimized solar heating cost in 25,000 Btu/degree-day house, capital charges @ 6% 20 years (1961)		Electric heating, usage 30,000 kwh/year (1970)	Fuel heating, fuel cost only (1970)	
	Collector @ $2/ft 2/	Collector @ $4/ft 2/		Gas	Oil
Santa Maria	1.10	1.59	1/ 4.28	1.52	1.91
Albuquerque	1.60	2.32	4.63	0.95	2.44
Phoenix	2.05	3.09	5.07	0.85	1.89
Omaha	2.45	2.98	3/ 3.25	1.12	1.56
Boston	2.50	3.02	5.25	1.85	2.08
Charleston	2.55	3.56	4.22	1.03	1.83
Seattle-Tacoma	2.60	3.82	2,3/ 2.29	1.96	2.36
Miami	4.05	4.64	4.87	3.01	2.04

1/ Electric power costs are for Santa Barbara. Electric power data for Santa Maria were not available.

2/ Electric power costs are for Seattle

3/ Publicly owned utility.

Solar heat costs are from optimal design systems yielding least cost heat.

Electric power heat costs are from U.S. Federal Power Commission, All Electric Homes, Table 2 (1970). Conventional heat fuel costs are derived from prices per million Btu reported in P. Balestra, The Demand for Natural Gas in the United States, Tables 1.2 and 1.3 (North Holland Publishing Co., 1967). The 1962 costs were updated to 1970 by use of national price indexes on gas (121.1 in 1970 versus 112.8 in 1962) and on fuel oil (119.22 in 1972 versus 101.2 in 1962) as adjustment factors on each fuel price in each state. Bureau of Labor statistics fuel prices indexes obtained from Gas Facts. Fuel prices were converted to fuel costs by dividing by the following national average heat (combustion) efficiencies: gas, 75%, oil, 75%. Heat efficiencies are from American Society of Heating, Refrigerating and Air Conditioning Engineers, Guide and Data Book 692-694 (1963 ed.)

All solar heat costs based on amortizing entire solar system capital costs in 20 years at 6 percent interest. Capital investment on current prices of solar water heaters at $4 per sq.ft. plus current costs of other components and on anticipated near-term solar collector price of $2 per sq.ft.

Source: "An Assessment of Solar Energy as a National Energy Resource," prepared by the NSF/NASA Solar Energy Panel, Dec. 1972.

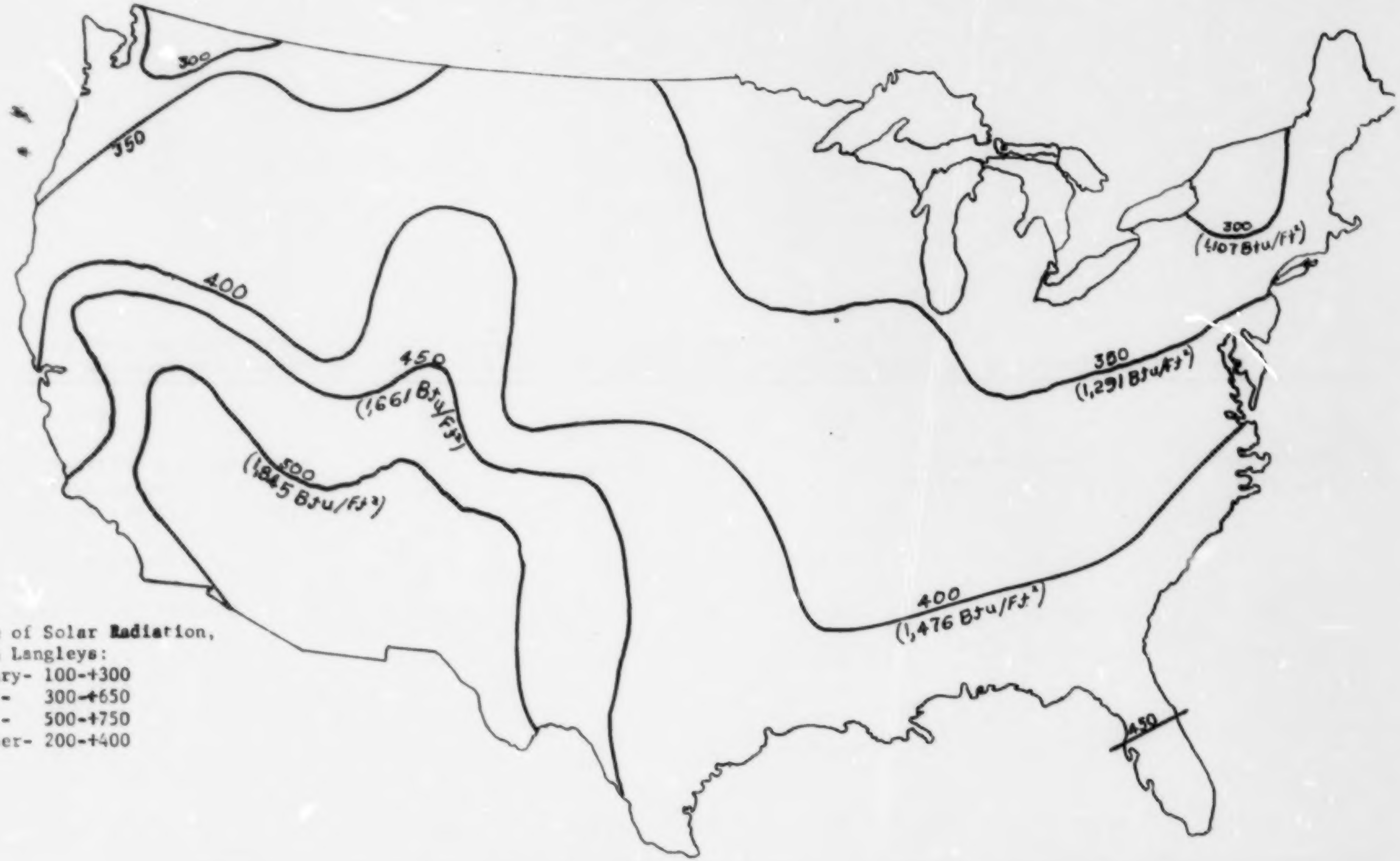
Based on Tybout, R.A. and Lof, G.O.G., "Solar House Heating," Natural Resources Journal vol. 10, no. 2, April 1970, pp. 268-326

Table 2. Electrical generation cost comparisons (estimated)

	Type of Powerplant				Satellite solar powerstation			Terrestrial
	Coal-fired	Oil-fired	Gas-fired	Nuclear	Low	Med.	High	Solar powerstation
Unit investment cost of plant, \$/kw	270	150	140	400	1,400	2,100	2,600	1,100
Annual fixed charges, percent of investment	17	17	17	17		17		17
Kilowatt-hours generated per year per kilowatt capacity	7,000	7,000	7,000	7,000		8,760		4,000 *
Efficiency, percent	34	34	34	33		11		30
Cost of fuel, ¢/10^6 Btu	36.2	55.2	29.4	17.5		0		0
Cost of electricity, mills/kwh:								
Plant investment	4.8	3.4	3.2	7.3	27.2	40.7	50.5	46.7 **
Operation & maintenance	1.0	0.6	0.5	0.4		undetermined		undetermined
Fuel	3.6	5.5	3.0	1.7		0		0
Total	9.4	9.5	6.7	9.4		--		--

* Maximum; assumes no facilities for storing electricity for use at night or on cloudy days.

** Less if facilities for storing electricity are available.


300
350
400
450
(1,661 Btu/Ft²)
500
(1,845 Btu/Ft²)
400
(1,476 Btu/Ft²)
380
(1,291 Btu/Ft²)
300
(1,107 Btu/Ft²)
450

ange of Solar **Radiation**,
in Langleys:
anuary- 100-+300
pril- 300-+650
uly - 500-+750
ctober- 200-+400

FIGURE 1. Annual Mean Solar Radiation. Incoming Radiation in Langleys/day (converted to Btu/square ft. on the basis of one Langley=3.69 Btu/ft^2, Per "Direct Use of the Sun's Energy," by Farrington Daniels, Yale Univ. Press 1964)

Source: U.S. Geological Survey, National Atlas

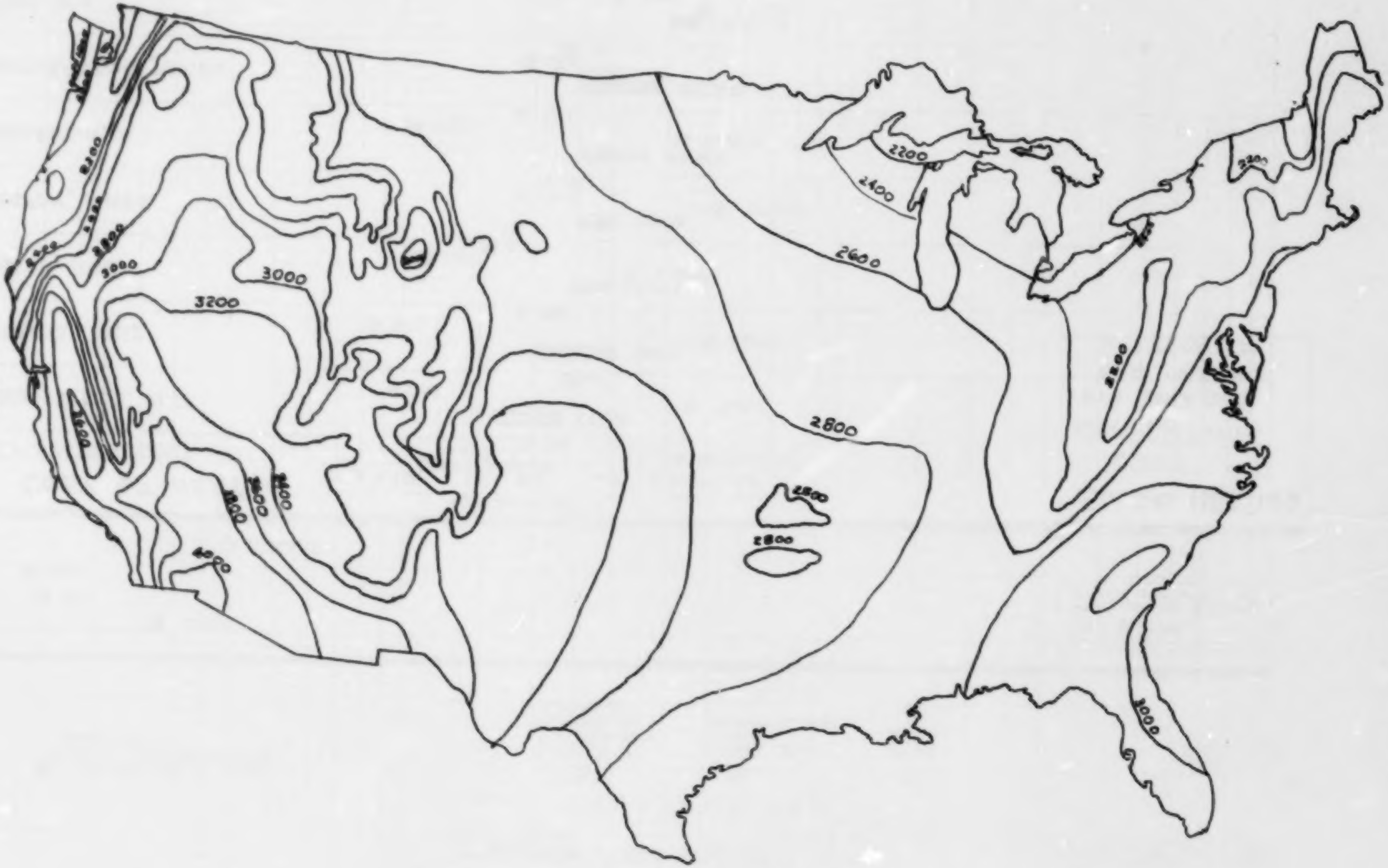
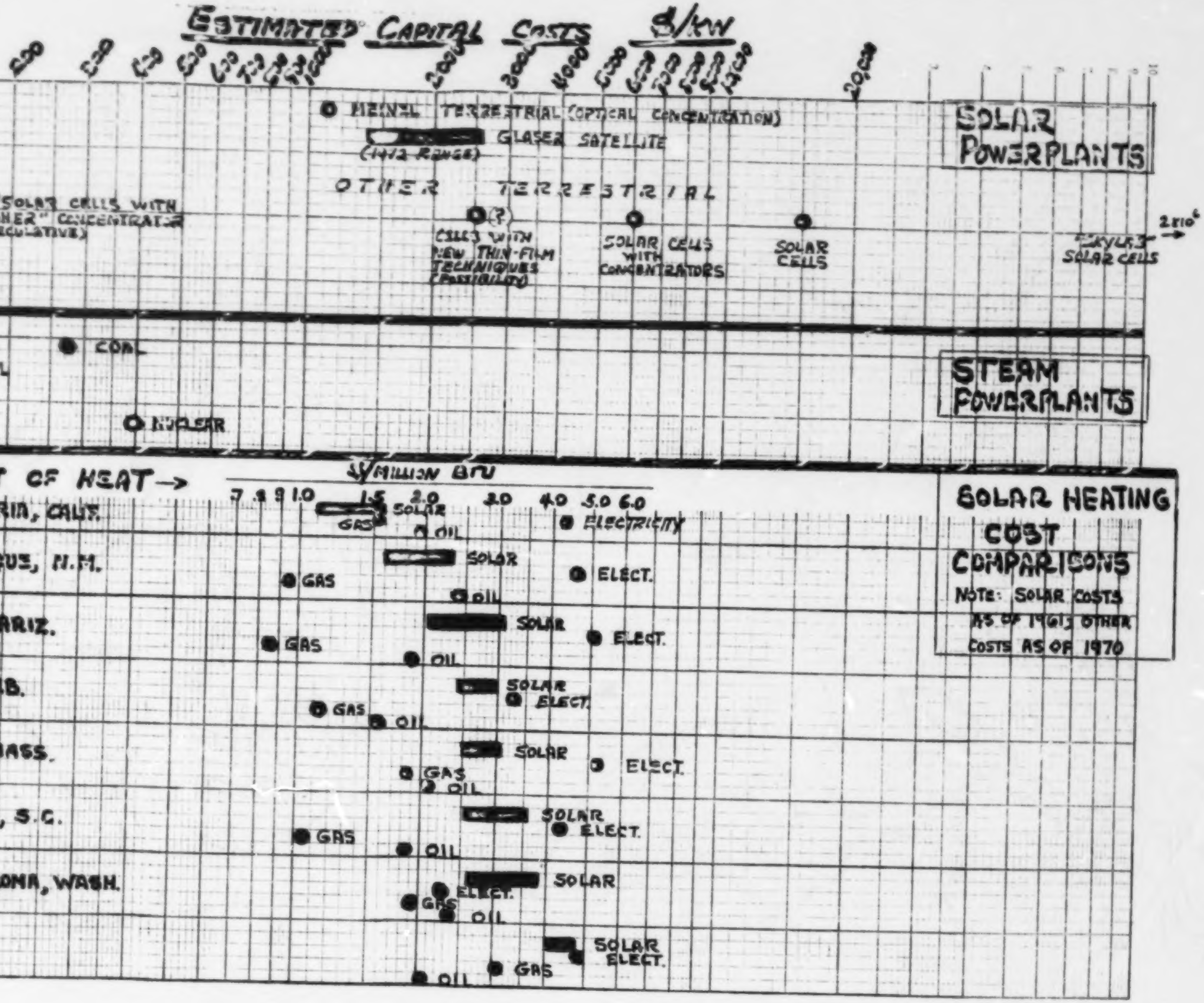

2200
2400
2600
2800
2800
2800
2200
2800
3000
2800
3000
3000
3200
3600
3400
3600
3800
4000
2200
3000

FIGURE 2. Mean Annual Sunshine hours (Range 1,600 to +4,000 hrs/yr)

Source: U.S. Geological Survey, National Atlas

FIGURE 3.


ESTIMATED CAPITAL COSTS $/KW
100
200
300
400
500
600
700
800
900
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
20,000
SOLAR POWERPLANTS
MEINEL TERRESTRIAL (OPTICAL CONCENTRATION)
GLASER SATELLITE
(1412 RANGE)
OTHER TERRESTRIAL
(?) SOLAR CELLS WITH "HIGHER" CONCENTRATOR (SPECULATIVE)
(?) CELLS WITH NEW THIN-FILM TECHNIQUES (POSSIBILITY)
SOLAR CELLS WITH CONCENTRATORS
SOLAR CELLS
SKYLAB SOLAR CELLS
2x10⁶ →
STEAM POWERPLANTS
OIL
GAS
COAL
NUCLEAR
COST OF HEAT →
$/MILLION BTU
.7
.8
.9
1.0
1.5
2.0
3.0
4.0
5.0
6.0
SOLAR HEATING COST COMPARISONS
NOTE: SOLAR COSTS AS OF 1961; OTHER COSTS AS OF 1970
SANTA MARIA, CALIF.
GAS
SOLAR
OIL
ELECTRICITY
ALBUQUERQUE, N.M.
SOLAR
GAS
ELECT.
OIL
PHOENIX, ARIZ.
SOLAR
GAS
ELECT.
OIL
OMAHA, NEB.
SOLAR
ELECT.
GAS
OIL
BOSTON, MASS.
SOLAR
ELECT.
GAS
OIL
CHARLESTON, S.C.
SOLAR
ELECT.
GAS
OIL
SEATTLE-TACOMA, WASH.
SOLAR
ELECT.
GAS
OIL
MIAMI, FLA.
SOLAR
ELECT.
GAS
OIL

Shale Oil

Oil shales of the Rocky Mountain region have been long heralded as a future supplemental source of oil. However, until recently there has not been sufficient economic incentive to induce committment of capital for starting a shale oil industry. However, the research and development conducted over many years has advanced technology to a point that makes commercial shale oil production technologically feasible.

The economic picture for oil shale has brightened greatly, and the outlook now is that oil shale development will begin in the relatively near future. A Government program to stimulate such development and evaluate environmental effects, and the interest and activities of a number of companies are contributary to this outlook.

Reserves/Resources

Oil shales of the Green River formation in Colorado, Utah, and Wyoming represent a very large energy resource. Estimates of oil in place, based on Geological Survey Paper 820, in high-grade and medium-grade shales comprising the identified shale oil resources in this formation are shown in Table 1.

Table 1. - Identified shale oil resources of Colorado, Utah and Wyoming (Billion 42-gallon barrels)

Grade of Shale	Oil in place			
	Colorado	Utah	Wyoming	Total
25 to 100gal/ton	355	50	13	418
10 to 25gal/ton	840	270	290	1,400
Totals (rounded)	1,200	320	320	1,820

The 1.8 trillion barrels represents the total identified shale oil resource in rich and medium grade shales. It represents oil in place, not recoverable oil. It is based on sequences of strata at least 15 feet thick averaging at least 15 gallons per ton. However, sequences yielding as little as 10 gallons per ton were included when computing the average yield of thick sequences.

The above resource estimates do not reflect the potential of undiscovered shale oil deposits. Such deposits have been estimated by the Geological Survey to be quite large.

Only a relatively small portion of the estimated 1.8 trillion barrels of identified shale oil resources in the Green River formation can be regarded as likely to be economically recoverable using present technology. Some of the beds are too lean to be of commercial interest; the mining method that has been used to date for these oil shales would be applicable to only a portion of the formation; and some of the shale in the areas mined would be left for roof support.

Of an estimated 160 billion barrels of inplace oil in shales 25 feet or more thick, averaging 30 to 35 gallons per ton and lying less than 1,000 feet below the surface, 80 billion barrels is considered to be recoverable using present technology, i.e., room-and-pillar mining and aboveground retorting.

It appears likely that openpit mining may be used for some areas of the formation, and higher percentages probably can be recovered by this method. Also, technology that may be perfected in the future, such as new mining methods and in situ retorting techniques, are

are expected eventually to make possible the recovery of a much larger portion of the oil in the Green River Formation. Escalation of oil prices over the next few decades also could have an important bearing on the amount of shale oil that eventually will be obtained from the formation.

Technology

Oil shales consist of solid, largely insoluble organic material intimately associated with a mixture of inorganic minerals. When heated to a temperature of around 900° F, the organic material undergoes pyrolysis, the products of which are oil, gas, and coke. Efforts to develop shale oil production technology along conventional lines--mining, crushing, and aboveground retorting--have been in progress for many years. More recently a considerable amount of research and development effort has been directed toward in situ retorting.

An underground method of mining Mahogany Zone oil shale was developed and demonstrated by the Bureau of Mines at its oil-shale facility near Rifle, Colorado, during the period 1944-56. Pillars of shale 73 feet high, 60 feet square, and 60 feet apart, supported the roofstone and several hundred feet of overburden. The system could be applied to a large area in the southern part of the Piceance Creek Basin. In eastern Utah, along some of the shale outcrop area of the Uintah Basin, the system also would be applicable. In non-outcrop areas access to shale beds to be mined would be by a vertical or inclined shaft. Union Oil Company of California operated a similar mine in the middle 1950's. More recently a room-and-pillar system with more modern machinery and improved techniques has been used by Colony Development Operation, a four company joint venture at its semiworks facility. Adaptation of open pit technology to the mining of oil shale has been proposed for areas where the ratio of minable shale to overburden and other factors are favorable.

The Gas Combustion retorting process was developed and tested by the Bureau of Mines through three pilot-plant stages, the largest having a capacity of about 300 tons per day. Two other aboveground retorting processes known as Union A and Tosco II have been developed through pilot plant stages and have been tested in experimental semiworks plants each having a single retort having a capacity of about 1,000 tons per day or a little more; the Union retort was operated at rates up to 1,200 tons of shale per day. "Union" connotes Union Oil Company of California and "Tosco" is a contraction of The Oil Shale Corporation. The Colony group completed its retorting program in 1972 in the semiworks Tosco II plant. A vertical shaft retort of large pilot plant proportions is to be operated at the Bureau of Mines experimental oil shale facility near Rifle, Colorado. Use of the facility has been made available under a lease agreement. Development Engineering, Inc. is acting as operator with 17 companies participating and providing financial support. The retort will be an adaptation of a limestone calcining kiln developed by Paraho Development Corporation.

In situ retorting technology in general is not as far along as the underground mining-aboveground retorting approach. However, both industry and the Bureau of Mines have made progress on development of in situ techniques. Currently, Garrett Research and Development Co., a division of Occidental Petroleum Corp., has an in situ project in operation. Results have been described as encouraging, with 25-30 barrels of oil being produced daily and good recovery efficiency reported. There have been reports that Occidental may undertake a large scale in situ project.

Although the composition and properties of shale oil differ from those of petroleum in several important respects, numerous combinations of modern petroleum refining techniques can be applied successfully to shale oil. This has been demonstrated by both industry and the Bureau of Mines in various sizes of processing equipment. One approach is to produce a high-quality syncrude by a pre-refining procedure involving hydrogenation. This oil would be pipelined to a refinery. The naphtha fraction of the syncrude could be catalytically reformed to produce a satisfactory yield of high-quality gasoline. Shale oil refining procedures can be designed, if desired, to produce a high proportion of low-sulfur fuel oil. Excellent yields of high-quality jet, diesel, and distillate fuels also can be obtained.

In addition to liquid fuels, products resulting from shale oil refining probably will include coke, solvents, paraffin wax, asphalt, tar acids, tar bases, and petrochemical plant feedstocks (such as ethylene, propylene, butylene, benzene, and naphtha). Sulfur and ammonia will be important inorganic coproducts and are expected to be produced in rather large quantities. There is a possibility of coproducing alumina and soda ash in addition to shale oil from the dawsonite and nahcolite-bearing oil shale deposits in the north central part of Colorado's Piceance Creek Basin.

Recent Developments

The Department of the Interior has undertaken a prototype leasing program whose objective is to stimulate development on a few lease tracts. The program will make available to industry two lease tracts (approximately 5,100 acres each) of high quality oil shale land in each of the three States--Colorado, Utah, and Wyoming. The publically owned oil shale lands were withdrawn from lease or other disposition by Executive Order 5327 of April 5, 1930, which still is in effect. However, legal arrangements have been made to allow the prototype program to go forward.

Protection of the environment is an important part of the program. The plan will insure that the area's water, land, air, wildlife, and other resources will be preserved or reclaimed for future generations.

Over the past three years the Department has conducted the pre-leasing phases of this program with the cooperation and active participation of the three State Governments and of industry. This work included preparation of leasing regulations and an impact statement, which was released August 30, 1973.

Lease sales have been held on the two tracts in Colorado. A high bonus bid of $210.3 million was received on the first tract. The high bid on the second tract was $117.78 million. Two major oil companies jointly offered the bid on the first tract, and four major oil companies jointly made the bid on the second tract.

In addition to the projects expected under the prototype leasing program, there are reports of other commercial shale oil projects in the making. One company is reported to be planning for startup of a 50,000 barrel per day before the end of 1977. Another is reported to be planning toward startup of a plant of about the same size in 1979. Others are operating experimental projects on the recovery of oil from oil shale.

Based on the above described activities, there appears to be little room for doubt that an oil shale industry will get started.

Economics

The recent excalation in petroleum prices has greatly improved the outlook for shale oil development. The intentions of several companies to build commercial plants would indicate a conviction on their part of the economic feasibility of shale oil production.

Presently available economic studies on anticipated shale oil production are based on cost and price data that are not current and would have to be updated to give a true picture. This is due to the effect of the accellerated inflation over the last year or two on costs and the higher prices of oil evident in recent months. Beyond updating to the present, a judgment then would have to be made with regard to the effects of enflation at the time a contemplated plant is to be built and the prices to be obtained for its products over the life of the plant. Two economic studies, though somewhat out of date, are summarized here without any adjustments for inflation or for the higher product prices.

A 1971 economic study by the Bureau of Mines (TPR 44) concludes that a selling price at the production facility of $3.74 per barrel of high quality semirefined shale oil would be necessary to maintain a discounted cash-flow rate of 12 percent. The plan envisioned in the study involves underground mining of 30-gallon-per-ton shale. The partial refining or upgrading involves coking and hydrocracking.

Upgrading of shale oil by a refining procedure such as this, including hydrogenation, results in a premium quality product, often referred to as shale oil syncrude. It probably would be worth approximately 50 cents per barrel more than an average grade petroleum.

The oil shale task group of the National Petroleum Council (NPC) completed an initial appraisal in 1972 and issued a final report in 1973. This was part of a study of the U.S. energy outlook to 1985, which the Council conducted for the Interior Department. The NPC oil shale task group estimated prices for several sets of assumptions, involving such important factors as type of mine, grade of shale, rate of return, and size of contingency allowance included in processing plant capital costs.

For initial production from 36 gallon per ton shale, according to the NPC study, a price of $3.90 per barrel in constant 1970 dollars would be required for a 10 percent DCF rate of return, $5.00 for a 15 percent rate and $6.35 for a 20 percent rate. The shale oil syncrude corresponding to these estimates would be a 46° API, hydrotreated distillate, virtually free of sulfur and low in nitrogen. It would be a premium refinery feedstock.

A study would be required to determine the increase in costs and prices since 1970 applicable to a shale oil plant. Refinery construction costs have increased by about one-third since 1970. Transporting shale oil from the upgrading facility to the St Louis-Chicago area would cost approximately 50 cents per barrel.

Forecasts to Year 2000

The initial plants are expected to come onstream in the late 1970's and early 1980's. The output of an individual plant built during this pioneering stage probably will be of the order of 50,000 barrels per day. Under the Interior Department's prototype leasing program, up to six tracts may be leased. With a 50,000 barrel per day plant on each tract, production on public lands thus would reach approximately 250,000 barrels per day. A few plants also may be built on privately owned lands. After some commercial production experience has been gained, larger plants probably will be built.

Shale oil production capacity of 1 million barrels per day between 1985 and 1990 seems probable.

The year 2000 forecast is 1 1/2 billion barrels annually (over 4 million barrels daily). Shale oil produced at this rate would constitute a little more than 11 percent of the total oil requirements forecast for the Nation.

Environmental Considerations

A high degree of public interest and concern exists in the anticipated development of an oil shale industry to utilize the oil shales of the Green River formation in Colorado, Utah and Wyoming. Minimizing adverse environmental effects will be emphasized. An important aspect of the prototype leasing program is that it will provide experience and information on environmental protection before any determination is made relative to larger scale leasing and development on public oil shale lands.

The area in which the oil shale deposits lie is sparcely populated. Much of it has scenic and open space values. Parts of the area are known for huge deer and elk populations. A large share of the area also is prime habitat for several hundred species of birds, mammals, fish, reptiles, and amphibians.

Environmental impacts will include those on the land itself, on water resources and air quality, on fish and wildlife habitat, on grazing and agricultural activities, on recreation, on aesthetic values, and on the existing social and economic patterns. Measures to minimize environmental damage, among other things, will involve the use of appropriate techniques for solid waste management, restoration and vegetation of disturbed lands including surface disposal sites for spent shale and steps to protect fish and wildlife.

Studies to date indicate that with orderly development environmental impacts can be adequately controlled. However, environmental considerations may act as a constraint on the growth of a shale oil industry.

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TAR SANDS

The Athabasca tar-sand deposit in Alberta, Canada is the largest one in the world and is one of the world's largest known oil accumulations. The nearly Bluesky-Gething and Grand Rapids tar sand deposits of Alberta also are important hydrocarbon resources. The world's first commercial oil from tar sands plant is producing approximating 45,000 barrels per day from the Athabasca tar sands. Oil from the tar sands of Alberta may contribute appreciably to future U.S. oil supply and therefore is potentially of importance to the United States. The imported oil would be expected to be consumed in the midwest.

There are many tar-sand occurrences in a number of countries throughout the world, including the United States. The largest domestic tar-sand deposits are in Utah, California, Texas, New Mexico, and Kentucky; in size they rank in that order. However, tar sands occur in 22 States and there are 546 known occurrences in those States. These domestic tar sands constitute a minor but nevertheless significant oil resource. It appears unlikely that domestic tar sands will be developed in the near future. Over a period of two or three decades they may supply a small but significant amount of oil.

Tar sands are oil-, bitumen-, asphalt-, tar-, or petroleum-impregnated rock from which little hydrocarbon material is recoverable by conventional crude oil production techniques.

RESERVES/RESOURCES

Until about the mid-1950's tar sand deposits were not regarded as having economic importance unless their characteristics were such as to render large-scale mining operations feasible. Since the late 1950's thermal in situ methods have been regarded as the probable technological route for recovery of oil from most domestic deposits and most of the Athabasca deposit.

Bitumen deposits are spread over approximately 30,000 square miles in the northern part of Canada's Province of Alberta. One estimate places the oil content of the Alberta tar sands at about 710 billion barrels with about 445 billion barrels regarded as potentially recoverable, including the oil that would have to be recovered by in situ technology. Two other estimates place the recoverable resource at 250 and 300 billion barrels respectively. The National Petroleum Council (NPC), in its 1972 report U.S. Energy Outlook, estimates the reserves in Alberta at 400 billion barrels of bitumen from which it estimates that 174 billion barrels of syncrude can be recovered. Of that total, the estimate shows 54 billion barrels recoverable by mining and aboveground processing and 120 billion barrels by in situ methods. The NPC points out that only about one-fifth of the area encompassed by the deposits has been proved by drilling. Further, some sites in the general areas where only in situ methods would apply may not have all the characteristics required for successful in situ operations. For these reasons its estimate is more conservative than the earlier ones.

The area of greatest interest, known as the Athabasca deposit, is limited to approximately 10,000 square miles, with portions of the deposit lying on either side of the Athabasca River, in the vicinity of Fort McMurray. This area is estimated to contain some 600 billion barrels of oil in place. The beds of Athabasca tar sands range in thickness up to 300 feet and vary in oil saturation. Near the Athabasca River, the tar sand beds are close to the surface, but along the southern and western edges of the oil bearing portions, they are as much as 2000 feet deep. Mineable portions of the deposit extend over an area of approximately 1000 square miles; the in situ resource area of the Athabasca deposit covers approximately 9000 square miles.

Areas of Alberta's tar sand deposits where the overburden is not too great are considered suitable for open-pit or strip mining, but generally, the portions of the deposits that lie beneath overburden greater than about 250 feet are considered to be economically recoverable only by in situ methods. Surface mining methods may be applied to most areas where the overburden is less than this and perhaps in some instances where it is a little greater. By far the major portion of the deposits fall into the in situ category.

Mineable reserves extend over an area of approximately 1000 square miles and have an estimated in place oil content of 120 billion barrels. The amount of synthetic crude that can be recovered economically from these Athabasca mineable reserves is estimated by the NPC at 54 billion barrels.

The extent and character of the tar-sand deposits in the United States are poorly defined; consequently, their potential as an energy resource can only be approximated. During the last two decades several estimates of the magnitude of this resource in terms of in-place oil content have been made and have ranged from about 2½ billion barrels to about 35 billion barrels. The various estimates are on different bases and therefore are not directly comparable. However, the estimates tend to grow as a result of additions to knowledge of the resource and advances in technology.

Bureau of Mines Monograph 12, compiled by Ball Associates and Published in 1965, contains an estimate of reserves recoverable through mining of the rock and extraction of the bitumen aboveground. It represents a survey of surface and near surface petroleum-impregnated rocks and their extensions to 500 feet. The estimate was 2.5 to 5.5 billion barrels.

Somewhat more recent reports 1/ 2/ 3/ describes the magnitude of the In-place oil resource in U.S. tar sands at 25 to 35 billion barrels, of which the deposits in Utah account for 25 to 30 billion barrels. The estimate shown for California is 169-322 million barrels. The New Mexico estimate is 37 million barrels and Kentucky 34-37 million barrels.

1/ Dietzman, W.D., M. Carreles, Jr. and C.J. Jirik. Heavy Crude Oil Reservoirs of the United States: A Survey. Bu Mines information Circular 8263, 1965.

2/ Extraction of Energy Fuels. Bu Mines Open File Report 30-73.

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The largest tar sand concentrations in Utah are the P.R. Spring deposit and the Tar Sands Triangle, which is composed of several deposits. Others in the over-1-billion barrel category are Sunnyside, Circle Cliffs and Asphalt Ridge. Utah also has several smaller deposits.

What portion of these estimated amounts may be economically recoverable is not known. The amount likely to be recovered will depend to a large extent on future technological developments particularly the development of in situ technology. No attempt has been made to estimate the amount of recoverable oil since 1952, when the consulting firm of Ford, Bacon, and Davis, Inc. conducted a survey as part of an evaluation of the synthetic liquid fuel potential of the United States. Their estimate of recoverable reserves of oil from domestic tar sands was 0.711 billion barrels this figure represented oil then regarded as recoverable from deposits in Utah, California, and Kentucky. Only deposits containing more than 10 million tons in a 5 square mile area with a minimum bed thickness of 15 feet and a maximum ratio of overburden to bed thickness of 1 : 1 were included in the estimate.

TECHNOLOGY

Characteristics of tar sands vary from one deposit to another, with respect to both the host rock and the impregnating material. In general, however, they are considered to be deposits of sand or rock with void spaces that are impregnated with dense, viscous petroleum. The impregnating materials vary from semi-liquid to semi-solid and in some cases solid petroleum materials. Rock types include dolomite, limestone, conglomerate, and shale, as well as consolidated sandstone and unconsolidated sand. The petroleums range from forms oozing slowly from an outcrop on a warm day to forms difficult to soften in boiling water. Tar sands are known also as oil sands and bituminous sands. Traditionally, tar sands have been treated as a petroleum supplement although in reality the organic material in tar sands is a form of petroleum. The real difference is that tar-sand-oil is not producible by the methods commonly used in ordinary oil fields. Also, the bitumen contained in the tar sands is too dense (usually 6-10° API) and too viscous (5,000-50,000 P at 50°F), to be transportable by pipeline without first being upgraded to an oil resembling conventional petroleum.

Though there are many potential processes for extracting oil from tar sands, the ones that are best known fall into two general categories -- in situ methods in which steam or heat in some other form is applied without removing the tar sand from the formation, and hot water processing of the tar sand after its removal from the formation by mining. Most of the technologic experience in obtaining oil from tar sands has been in Alberta, Canada, on the Athabasca deposit though some experience has been gained in the United States and some in Venezuela.

Great Canadian Oil Sands, Ltd. (GCOS), which is owned principally by Sun Oil Company, Ltd., was granted permission by the Alberta Government to build the first commercial tar sands plant. This plant is producing at approximately the design capacity of 45,000 barrels per calendar day of syncrude. Construction was started in 1964, and the plant has been in operation since August 1967.

The GCOS plant was designed to include the following:

1. A heavy-duty bucket wheel excavator capable of handling 60 thousand cubic yards (approx. 100,000 tons) of material daily.

2. A high speed conveyor system to carry the sands to an extraction plant.

3. An extraction plant which separates the oil or bitumen from the sands by a hot-water process. This plant produces approximate 65,000 barrels per day of crude oil or bitumen.

4. Refining units which upgrade the bitumen by coking and hydrogenation to produce 45,000 barrels per day of high-quality, high-gravity synthetic crude oil. These units include a coking plant capable of processing 65,000 barrels of crude per day, a 60,000 cubic feet per day hydrogen plant, a 55,000 barrel per day desulfurizer and a 400 ton-per-day sulfur plant.

5. A tank farm with a storage capacity of over 1 million barrels.

6. A 266 mile 16-inch pipeline and pumping stations from the production facility to a tank farm and connecting pipelines at Edmonton.

7. A large coke-fired steam plant and electric generating plant.

8. An all-weather road from Fort McMurray to the project including a bridge across the Athabasca River and various supporting and general facilities.

RECENT DEVELOPMENTS

GCOS plans to increase production to 65,000 b/d of syncrude. Syncrude Canada Ltd., a four-company consortium, plans to build a 125,000 b/d facility; site work has begun and startup is expected in 1977. A 100,000 b/d plant is planned by Shell Canada Ltd., with startup scheduled for 1980. A group of five companies headed by Petrofina Canada Ltd. proposes to build a plant with a capacity of 122,500 b/d. Their plans call for pilot testing and process optimization before final engineering design of the proposed facility. The plant according to their schedule would come on stream in 1982.

Implementation of the plans of all these companies is contingent on approval by the Alberta provincial governments. Permits have been applied for, and Alberta's Energy Resources Conservation Board (ERCB) has recommended approval of the GCOS and Syncrude applications. The other two applications have been accepted for consideration by ERCB.

The plans for the Syncrude, Shell, and Petrofina plants, are all based on mining and aboveground processing to extract the oil. The crude oil thus obtained will have to be upgraded before it enters a pipeline. The mining and processing technologies of their plants are expected to be generally similar to that of the existing GCOS facility.

FORECASTS

The National Petroleum Council, according to its U.S. Energy Outlook (Dec. 1972), foresees production over the near to mid term from Canadian tar sands and heavy oil deposits as follows:

Year	1000 Barrels Daily
1975	50-75
1980	275-500
1985	500-1,250

Imperial Oil Limited, in a presentation for hearings (Oct. 1972) held by the Alberta Energy Resources Conservation Board, estimated future production of oil from Alberta's tar sands according to the following schedule:

Year	1000 Barrels Daily
1975	75
1977	125
1978	300
1985	700
1990	1,500
2000	3,500

Others too have forecast production to increase at about this rate.

The National Petroleum Council (NPC) portrays a rising oil export capability through 1985 for Canada in its report U.S. Energy Outlook --Oil and Gas Availability. The total liquid hydrocarbon production available for net export is shown as 0.4 million barrels in 1975, 1.1 million barrels in 1980 and 1.7 to 2 million barrels in 1985. A rather large share of this export oil could come from tar sands. If as much as one-third of the 1.7 to 2 million barrels per day consists of tar sands oil exported to the U.S. it would account for around 600,000 barrels per day, i.e. most of the tar sands oil produced in 1985.

If half the previously mentioned tar sands oil production forecast for year 2000 were to flow to U.S. markets, the U.S. would receive approximately 1.75 million barrels per day of this oil. If the rise in Canadian oil exports foreseen by NPC for 1985 were to double by the end of the century, the 1.75 million barrels per day of tar sands oil would constitute around 45 to 50 percent of Canada's oil exports to the U.S.

Whether as large an amount of Canadian tar sands oil as this is likely to flow into the United States, however, is questionable at this point. It will depend, among other things, on policies of the Aberta provincial the government and the Canadian federal government. It will depend too on U.S. policies and on Canadian-U.S. interrelationships and agreements. It also will depend on Canada's future domestic oil demand/supply situation and its export/import situation.

As an example of a possible impact of government policies, there is the prospect of a goal of U.S. energy self-sufficiency. Also, in recent times, there have been indications of some thinking in terms of Canada's lessened dependence on insecure imported oil. With a realignment of Canadian energy policies emphasizing greater self-sufficiency, especially with regard to oil, the outlook for exports of tar sands oil to the U.S. would be dampened. The Canadian domestic supply with respect to domestic demand situation also can have a significant bearing. Oil prices can have a major influence on the rate of development of Canada's oil resources. According to an analysis by a Canadian government agency[5] production capacity projected for a case based on an international oil price of 4 dollars per barrel could result in a shortfall of domestic production as compared to domestic demand. However, with an international oil price of 6 dollars per barrel, domestic demand would exceed domestic production well beyond 2000.

Studies by Gulf Canada Ltd. and Shell Canada Ltd.,[6] portray a rather gloomy picture for 1980-1985. They indicate a peaking of production from traditional producing regions about 1976. They show a projection of Canada's oil needs from about 1.7 billion barrels at present to around 2.3 billion barrels in 1980 and 3.1 billion barrels in 1985. The Canadian production capability is seen as remaining approximately constant during that period, with the decline in production from currently producing regions barely being offset by increasing production from tar sands and oil from frontier regions.

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[5] An Energy Policy for Canada, issued under the authority of the Minister of Energy, Mines, and Resources, Ottawa, Canada (1973).

[6] "Artic Energy Vital to Head Off Shortfall in Canada", Oil & Gas Journal, Feb. 4, 1974, pp. 72-76.

Whereas Canada now produces more oil than it consumes, those studies indicate that Canada can be expected to experience a shortfall in domestic production as compared to domestic demand beginning shortly after 1980. By 1985 the shortfall would grow to around a half million barrels per day. At that time the studies anticipate a sharp increase in production from frontier regions, primarily arctic regions, especially the Mackenzie Delta area. This increase plus continuing expansion of production from tar sands could fill the gap between domestic production and consumption by about 1987. After that, Canada's production would exceed her demand and by 1990 would be greater by about 700,000 barrels per day.

Consider a scenario based on Canadian policy oriented toward energy self-sufficiency superimposed on this domestic supply/demand scenario. It would appear that the amounts of oil from Canadian tar sands likely to be delivered to the U.S. in 1985 and 2000 under those circumstances would be much less than the amounts previously mentioned; the amount by 2000 might be no more than a few hundred thousand barrels daily.

Production of oil from Utah's tar sands probably will never be much greater than 500,000 barrels per day. This is due to the limited number of sites where the reserves are adequate to support a production facility large enough to be economic. The NPC study concludes that anything more than token demonstration production by 2000 is doubtful. NPC expressed the view that any significant domestic production of oil from tar sands before 1985 is unlikely. The continuation of the current petroleum shortage and high oil prices in the U.S. could spur interest in domestic tar

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The domestic tar sands have not attracted much interest; research and development activity on Utah's tar sands, where interest would logically center, has been limited to a few sporadic short term small scale efforts. Some of the Athabasca technology probably could be adapted to some U.S. deposits. However, the deposits in Utah and others in this country have characteristics of their own that may require development of somewhat different or modified recovery techniques even for the more shallow deposits. Tapping of the deeper deposits will have to await the development of in-situ techniques.

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